3. WRITTEN AND ORAL COMMENTS AND DETAILED RESPONSES

Responses to Comments in Letter 1 from Verne Kucy, Manager Environmental Services Division, the Corporation of Delta

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Thank you for your comment. Figure 3.2-1 in the Final EIS has been changed to reflect the suggested revisions.

2. Thank you for your comment. Tsawwassen has been replaced with Delta on figures and in tables in the Final EIS.

3. The City of Surrey has been included in Figure 3.2-1 and other figures in the Final EIS.

4. Table 3.2-16 in the Draft EIS is correct. For eight-hour carbon monoxide (CO) readings, the maximum concentration of 4.8 micrograms per cubic meter in Canada is 7.8 miles north of the project on the U.S.-Canada border. The maximum CO concentration is projected to be at a slightly different location than that for other pollutants, which are 7.5 miles away from the project.

5. Thank you for your comment. Table 3.2-18 has been revised and the City of Delta now appears in the table.

Response to Comment in Letter 2 from Dr. Mary Lynn Derrington, Superintendent, Blaine School District 503

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Comment acknowledged.

Responses to Comments in Letter 3 from Sam Crawford, Whatcom County Council Member

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Comment acknowledged.

2. Thank you for your comment. The description of the No Action Alternative has been revised to reflect the air quality impacts.

3. Thank you for your comment. The description of the No Action Alternative has been revised to reflect the air quality impacts.

4. Thank you for your comment. The description of the No Action Alternative has been revised to reflect the environmental benefits.

5. Thank you for your comment. The description of the No Action Alternative has been revised to reflect the environmental benefits.

6. Thank you for your comment. The description of the No Action Alternative has been revised to reflect the environmental benefits.

7. Thank you for your comment. The description of the No Action Alternative has been revised to reflect the environmental benefits.

8. Thank you for your comment. The description of the No Action Alternative has been revised to reflect the environmental benefits.

9. Thank you for your comment. The description of the No Action Alternative has been revised to reflect the environmental benefits.

10. Thank you for your comment. The description of the No Action Alternative has been revised to reflect the economic benefits.

11. Thank you for your comment. The description of the No Action Alternative has been revised to reflect the economic benefits.

12. Thank you for your comment. The description of the No Action Alternative has been revised to reflect the economic benefits.

13. Thank you for your comment. The description of the No Action Alternative has been revised to reflect the economic benefits.

Responses to Comments in Letter 4 from Wyburn Bannerman, Ferndale Resident

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Thank you for your comment. It is Bonneville's normal practice to coordinate with landowners during the siting of electrical transmission towers. If new towers are erected as part of the proposed project, the selection of lattice or monopole towers will take into consideration costs, avoidance of natural resources, and landowners' preferences. Also, please refer to Response 4(2) of the Public Meeting comments.

Responses to Comments in Letter 5 from S. Gilfillan

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Thank you for your comment.

2. Thank you for your comment. Potential impacts on air quality, wetlands, and wildlife habitats were assessed in Sections 3.2, 3.5, and 3.7, respectively, of the Draft EIS. The results of the assessment did not identify significant impacts on these resources. Those impacts that were identified will be mitigated by the Applicant through compliance with the conditions in the Site Certification Agreement and permit conditions approved by federal regulatory agencies, if the project is approved.

Responses to Comments in Letter 6 from Doug Caldwell

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. The commenter indicates that selective catalytic reduction (SCR) technology can be the source of nitrosamines and hydrogen cyanide. The commenter has attached excerpts from a 1989 report indicating that although the production of nitrosamines and hydrogen cyanide is possible if the combustion gases entering the SCR unit contain hydrocarbons, the formation of both cyanide compounds and nitrosamines is extremely unlikely. SCR technology has been in operation for 20 years at facilities all over the world with no indication of safety concerns related to cyanide compounds or nitrosamines. It is the generally accepted control technology of choice for NO_x emissions control for this type of application.

   The commenter's submittal indicates that the emissions control technology manufactured by ISCA Management Ltd. should be chosen over SCR technology because it controls sulfur oxides and heavy metals in addition to NO_x. The choice of emissions control technology is based on rigorous review according to state and federal laws and regulations. Best Available Control Technology (BACT) must be technically feasible and cost-justified. The technology being proposed by ISCA Management Ltd. has not been demonstrated as technically feasible or commercially available on any combustion turbine facility similar in nature or size to this project. The ISCA technology, therefore, would not meet BACT under the requirements of the Prevention of Significant Deterioration program.

Responses to Comments in Letter 7 from H. J. Schneider, Blaine Resident

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Thank you for your comment. The project would incorporate into the design the Best Available Control Technology (BACT) for criteria pollutant emissions.

2. Please refer to General Response A.

3. New transmission lines from the cogeneration facility will connect to Bonneville's existing powerline grid system approximately 0.8 mile east of the facility. No new lines connecting to Vancouver, Canada, will be constructed.

4. Tables 3.2-32 and 3.2-33 in the Final EIS show the worst-case cumulative effect of emissions from the Sumas 2 Project and the proposed BP Cherry Point Cogeneration Project.

5. Thank you for your comment. The proposed project does not include adding transmission lines or "links" between Canada and Anacortes.

Response to Comment in Letter 8 from Todd L. Harrison, WSDOT, Northwest Region/Mount Baker Area

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. The Draft EIS has been revised to reflect that no signal is proposed at the Blaine/Grandview intersection. The Applicant has reached an agreement with WSDOT that a signal will be installed at the intersection of Grandview Road and Portal Way and a left-turn lane will be established from westbound Grandview Road to Blaine Road.

Responses to Comments in Letter 9 from Senator Dale E. Brandland, 42nd District

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Thank you for your comment.

2. Thank you for your comment.

3. Thank you for your comment.

Responses to Comments in Letter 10 from State Representative Kelli Linville, 42nd District

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Thank you for your comment.

2. Thank you for your comment.

3. Thank you for your comment.

Response to Comment in Letter 11 from Gary Russell, Gerald Metzger, Michael Murphy, and Al Saab, Whatcom County Fire District No. 7

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Thank you for your comment.

Responses to Comments in Letter 12 from Arne R. Cleveland, Blaine Resident

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. You are correct. Analyses performed to evaluate impacts on ambient $PM_{2.5}$ concentrations resulting from project emissions have conservatively assumed that all particulate matter emitted is 2.5 microns or less in diameter.

2. The U.S. Environmental Protection Agency has established National Ambient Air Quality Standards (NAAQS) for $PM_{2.5}$. These standards, which are codified in Chapter 40, Section 50.7 of the Code of Federal Regulations (CFR), were established to protect human and environmental health against impacts associated with this pollutant. However, other than the NAAQS for Significant Impact Levels, incremental consumption standards have not yet been established in federal regulation (40 CFR 52.21).

   To assess the impacts of the $PM_{2.5}$ emissions on the NAAQS, the U.S. EPA allows PM_{10} to be used as a surrogate because there is no incremental standard for $PM_{2.5}$ established in 40 CFR 52.21. The Applicant has demonstrated that the project's PM_{10} emissions would be below the Significant Impact Level thresholds and would therefore not cause or contribute to a violation of the NAAQS for PM_{10}. Maximum ambient air concentrations of $PM_{2.5}$ that would result from the project are below the NAAQS established for $PM_{2.5}$, as shown in Table 3.2-11 of the Final EIS

3. As required by state and federal regulations under the Prevention of Significant Deterioration (PSD) review, the Applicant modeled project emissions to determine whether or not impacts on ambient air quality concentrations would exceed the Significant Impact Levels established by EPA. Under PSD regulations, only facilities with impacts that exceed Significant Impact Levels are required to include the impacts of other facilities within the modeling zone. The modeling demonstrated that the impacts of the project would be less than EPA's Significant Impact Levels. In fact, the Draft EIS determined that the project would not have any adverse impacts on ambient air quality in the project vicinity and would comply with all Washington State and national ambient air quality standards.

   The Applicant has, however, assessed the sum of the project emissions with existing ambient background levels for criteria pollutants regulated under the PSD program. These data were presented in the Draft EIS in Table 3.2-11 for U.S. locations, and Tables 3.2-15 and 3.2-16 for Canadian locations.

   In addition to the analyses performed under the PSD program, the combined impacts of the BP Cherry Point Cogeneration Project and the Sumas Energy 2 Generation Facility were conservatively evaluated. This analysis is included in Section 3.2 of the Final EIS.

4. As described in Section 3.9 Noise, of the Draft EIS, there would be no perceptible increase in noise at any of the studied receptor locations surrounding the facility.

5. As noted in Section 3.2 Air Quality in the Final EIS, the combined background and predicted concentrations for all criteria pollutants analyzed in the local area are less than the most stringent air quality standards. Section 3.9 Noise in the Draft EIS indicates there would be no perceptible increase in noise at any of the receptor locations surrounding the facility, including Birch Bay State Park. Also, please refer to General Response A for a description of alternative site analysis and an evaluation of the size of the proposed cogeneration facility.

Responses to Comments in Letter 13 from Bill Henshaw, Bellingham Resident

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Thank you for your comment. The employment benefits noted are correct. Under minimal water demand conditions and with Alcoa Intalco Works in operation, the cogeneration plant would reduce withdrawals from the Nooksack River by more than 700,000 gallons per day.

Responses to Comments in Letter 14 from James Randles, Director, Northwest Air Pollution Authority

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. The cited reference of BP 2002 is provided in Chapter 4 on page 4-2 of the Draft EIS. The reference is as follows: BP West Coast Products, LLC. June 2002 (including April 2003 revisions). *BP Cherry Point Cogeneration Project, Application for Site Certification*. Application No. 2002-01. Part I, Compliance Summary; Part II, Environmental Report; and Part III, Technical Appendices. Prepared by Golder Associates, Inc. for the Energy Facility Site Evaluation Council. Olympia, Wash.

2. The annual emission rates for toxic VOCs were identified in Table 3.2-13 of the Final EIS. These total 6,416.8 lbs/year and represent 7.6% of total facility VOC emissions.

3. Nitric oxide emissions, NO, were included in the evaluation of all nitrogen oxide (NO_x) emissions. The maximum modeled concentration of NO_x from the facility as a whole is 2 $\mu g/m^3$ on a 24-hour average, which is much lower than the 100 $\mu g/m^3$ Acceptable Source Impact Level.

Responses to Comments in Letter 15 from Rob Pochert, Executive Director, Bellingham Whatcom, Economic Development Council

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Thank you for your comment.

Response to Comment in Letter 16 from Preston Sleeger, Regional Environmental Officer, United States Department of the Interior

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Comment acknowledged.

Responses to Comments in Letter 17 from Gerald Steel,
Attorney-at-Law, Seattle

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. The design of the Applicant's project avoids many potentially adverse environmental impacts. Potential impacts that could not be avoided were evaluated and, with proposed mitigation, the resulting impacts are not considered significant. Assuming the project is approved, the Applicant will carry out stipulated mitigation measures contained in the Site Certification Agreement as well as conditions (general and specific) in the federal permits to be obtained by the Applicant. EFSEC and federal regulatory agencies will monitor the success of the mitigation designed and carried out by the Applicant.

2. Thank you for your comment. Recent research and analyses into the effects of global warming have identified global and regional impacts that may occur. There is uncertainty as to the time when such effects will be measurable and the magnitude of the impacts that may occur. Because of the nature of the models used to predict the effects of greenhouse gas (GHG) emissions on global warming and the global nature of the effects, there is insufficient information to predict the actual impacts resulting from the project's emissions alone. Additional information regarding GHG and global warming has been added to Sections 1.8.1 and 3.2.5 of the Final EIS.

3. As noted in Section 3.6 of the Draft EIS, the cogeneration facility (and in fact the entire project) is located on land zoned for industrial land uses; it therefore does not meet the federal definition for prime agricultural land. While the soils present on the site are those identified in Whatcom County Code 20.38 as "Agriculture Protection Overlay Soils," the code further states the provisions apply only to rural, not industrial, zoning designations.

4. Please refer to Response 3 of this letter. The project will burn a clean fuel, natural gas, and the resulting emissions will be dispersed over a wide area. Only a small fraction of the pollutants would remain in the project vicinity. When compared to coal and diesel fuel, natural gas combustion emits much lower quantities of criteria and toxic pollutants and is not a significant source of acid rain. Project emissions will be minimized through the use of Best Available Control Technology as explained in Section 3.2 of the Final EIS.

5. Water removed from the Nooksack River for use at Alcoa Intalco Works is discharged to the Strait of Georgia. If Alcoa Intalco Works is not in operation, the water that would have been transferred to the cogeneration facility for reuse would instead be delivered directly to the BP Cherry Point Refinery. There would be no increase in water withdrawn from the Nooksack River. All water used by the cogeneration facility would either evaporate in the cooling tower or be treated at the refinery's wastewater treatment facility and discharged to the Strait of Georgia. The water will not be distributed to the local microsystem or agricultural lands.

6. In accordance with the requirements of the Prevention of Significant Deterioration (PSD) program, the Applicant used the CALPUFF model to determine visibility in Class I areas in the U.S. PM_{10}, NO_X, and SO_2 were modeled with chemical transformations of secondary pollutants such as ammonia nitrate and ammonia sulfate, and the results were combined to calculate a visibility coefficient. The results were then compared with background data to calculate the percentage of visibility change.

   Table 3.2-12 of the Final EIS shows that the project emissions (excluding any emission reductions from removal of refinery boilers) predict a 5% visibility change for one day at one Class I area (Olympic National Park). Federal guidelines for determining the criteria used to define a significant impact on regional visibility from emissions at new air pollutant sources were recently published by the Federal Land Managers' Air Quality Related Values Workgroup in its Phase One Report, published by the U.S. Forest Service, National Park Service, and U.S. Fish and Wildlife Service in December 2001. According to the federal land mangers responsible for protecting air quality in Class I areas, a 5% change in extinction (a coefficient used to quantify how pollutants in the atmosphere reduce visual range) indicates a "just perceptible" change to a landscape and a 10% change is considered a significant incremental impact. The National Park land managers were consulted about the perceptible change caused by the project, and they consider it acceptable (Morse 2003).

   The Draft EIS assesses the cumulative impact on visibility from construction of the BP Cherry Point Cogeneration Project and other proposed power plants in the Pacific Northwest. Phase II of Bonneville's regional impact analysis addressed the visibility impacts of the BP Cherry Point Cogeneration Project in a "most likely" scenario of the Phase II baseline group. In other words, if all projects included in that baseline group were built, some impacts on visibility would most likely occur, as explained in detail in the Draft EIS, but visibility would not be permanently cut off.

<u>Exhibit 1</u>

1(1) The energy market in the Pacific Northwest has changed in the last 18 to 24 months; however, long-term regional energy needs require that additional facilities be constructed to meet regional demand within the next 10 years. Market forces will control which of the proposed facilities actually move forward to construction and operation once they have received environmental and other approvals.

The Northwest Power Pool comprises all or major portions of the states of Idaho, Montana, Nevada, Oregon, Utah, Washington, and Wyoming; a small portion of Northern California; and the Canadian provinces of British Columbia and Alberta. From 2003 through 2012, peak demand and annual energy requirements are projected to grow at annual compound rates of 1.6% and 1.7%, respectively. With a large percentage of hydro-generation in the region, the ability to meet peak demand is expected to be adequate for the next 10 years. Capacity margins for this winter peaking area range between 23.4% and 29.6% for the next 10 years.

As shown in the following table, a recent survey of large combustion turbine facility projects in the Pacific Northwest indicates that over 11,000 MW of large natural gas turbine proposals have been cancelled, denied permit, or delayed indefinitely, approximately 4,750 MW have been approved but have not started construction, and approximately 5,500 MW are undergoing review. In its most recent 10-year coordinated plan summary, the Western Electricity Coordinating Council projects that reserves will be adequate throughout the region through 2012, but only if 32,300 MW of new generation are brought on line when needed. Droughts in the Pacific Northwest may substantially reduce the availability of electricity for export from the region, and capacity becomes highly dependent on northwest hydroelectric conditions after 2008. The net power increase is projected to be 12,300 MW of committed resources and 20,000 MW of uncommitted resources.

The 546 MW for the Hermiston Power Project reflect the numbers presented in the 2001 Phase II study completed by Bonneville.

Summary of Proposed Combustion Turbine Facilities in the Pacific Northwest

Facility	County	Location	Technology	Output (MW)	Est. Online Date	Company
Operating Facilities						
Evander Andrews (Mt Home)	Elmore	Idaho	Gas Turbine	90	10/1/2001	Idaho Power Company
Rathdrum	Kootenai	Idaho		270	9/1/2001	Avista/Cogentrix
Exxon I	Yellowstone	Montana	Gas Turbine	20	4/1/2001	Exxon
Albany Cogeneration	Linn	Oregon	Cogen	85	7/1/2000	Williamette
Beaver GT	Columbia	Oregon	Gas Turbine	24	7/1/2001	Portland General Electric
Coyote Springs II	Morrow	Oregon	Combined	280	7/1/2003	Avista/Mirant
Hermiston	Umatilla	Oregon	Combined	530	8/20/2002	Calpine
Hermiston Peaking	Umatilla	Oregon	Combined	100	8/20/2002	Calpine
Klamath Falls Cogeneration	Klamath	Oregon	Combined	500	7/1/2001	PacifiCorp
Klamath Falls Expansion	Klamath	Oregon	Gas Turbine	100	6/1/2002	Pacific Klamath Energy
Morrow Power GT	Morrow	Oregon		25	8/1/2002	Morrow Power
SP Newsprint Cogen	Yamhill	Oregon	Combined	130	7/1/2003	SP Newsprint
Benton PUD (Finley)	Skagit	Washington	Gas Turbine	27	12/20/2001	Benton PUD
Big Hanaford (Centralia)	Lewis	Washington		248	7/1/2002	TransAlta
Boulder Park	Spokane	Washington		25	4/1/2002	Avista
BP Cherry Point GTs	Whatcom	Washington	Gas Turbine	73	9/1/2001	Cherry Point Refinery
Chehalis Generation	Lewis	Washington	Combined	520	10/1/2003	Tractebel
Equilon GTs	Skagit	Washington	Gas Turbine	38	1/1/2002	Equilon Enterprises

Summary of Proposed Combustion Turbine Facilities in the Pacific Northwest (cont.)

Facility	County	Location	Technology	Output (MW)	Est. Online Date	Company
Frederickson	Pierce	Washington		249	8/1/2002	EPCOR & Puget Sound Energy
Fredonia Addition	Skagit	Washington	Gas Turbine	106	8/1/2001	Puget Sound Energy
Pasco GTs	Franklin	Washington	Gas Turbine	44	6/30/2002	Franklin/Grays Harbor PUD
Pierce Power	Pierce	Washington	Gas Turbine	154	9/1/2001	TransAlta
SUBTOTAL				3,638		
Facilities Under Construction						
Frederickson Expansion	Pierce	Washington		25	6/1/2005	EPCOR & Puget Sound Energy
SUBTOTAL				25		
Regulatory Approval Received						
Bennett Mountain		Idaho	Peaker[1]	162	7/1/2005	Idaho Power
Silver Bow	Silver Bow	Montana	Combined	500	1/1/2011	Continental Energy Services
Port Westward	Columbia	Oregon	Combined	650	4/1/2006	Portland General Electric
Summit/Westward	Columbia	Oregon	Combined	520	4/1/2006	Westward Energy LLC
Umatilla Generation Project	Umatilla	Oregon	Combined	610	3/31/2008	PG&E Natl Energy
Frederickson Power 2	Pierce	Washington	Combined	300	1/1/2011	EPCOR & Puget Sound Energy
Sumas 2 Generating Facility	Whatcom	Washington	Combined	660	1/1/2011	National Energy
Wallula	Walla Walla	Washington	Combined	1,350	1/1/2011	Newport Generation
SUBTOTAL				4,752		
Under Review						
Rathdrum GT to CC Conversion	Kootenai	Idaho	Combined	90	9/1/2005	Avista
Basin Creek	Silver Bow	Montana	Reciprocating Engines	48	1/1/2011	Basin Creek Power
COB Energy Facility	Klamath	Oregon	Combined	1,150	6/1/2005	Peoples Energy
Klamath Generating Facility	Klamath	Oregon	Combined	500	1/1/2011	PacifiCorp Power Marketing
Turner	Marion	Oregon	Combined	620	1/1/2011	Calpine
Wanapa Energy Center	Umatilla	Oregon	Combined	1,230	1/1/2011	Eugene Water & Elec
West Cascade Energy Facility	Lane	Oregon		600	12/31/2007	Black Hills Corp
BP Cherry Point	Whatcom	Washington	Combined	720	6/1/2006	Cherry Point Refinery

1 A facility that operates during peak power demands.

Summary of Proposed Combustion Turbine Facilities in the Pacific Northwest (cont.)

Facility	County	Location	Technology	Output (MW)	Est. Online Date	Company
Plymouth Generating Facility	Benton	Washington	Combined	306	1/1/2011	Plymouth Energy
Tahoma Energy Center	Pierce	Washington	Combined	270	1/1/2011	Calpine
SUBTOTAL				5,534		
Cancelled, Denied Permit, or Delayed Indefinitely						
Garnet Energy Facility I	Canyon	Idaho	Combined	273		Ida-West
Garnet Energy Facility II	Canyon	Idaho	Combined	262		Ida-West
Kootenai	Kootenai	Idaho	Combined	1,300		Newport Generation
Mountain Home (PDA)	Elmore	Idaho	Gas Turbine	104		Power Development Association
Rathdrum II	Kootenai	Idaho	Combined	500		Cogentrix
Montana First Megawatts	Cascade	Montana	Combined	250		Northwestern Corp
Coburg	Lane	Oregon	Combined	605		Coburg Power
Columbia River Energy	Columbia	Oregon	GT	44		Columbia River Energy
Grizzly Power Project	Jefferson	Oregon	Combined	980		Cogentrix
Morrow	Morrow	Oregon	Combined	550		PG&E Natl Energy
Pope & Talbot Cogen (Halsey)	Linn	Oregon	Gas Turbine	93		Oregon Energy
St Helens Cogen	Columbia	Oregon	Combined	141		Oregon Energy
West Linn Paper	Clackamas	Oregon	Combined	94		West Linn Paper
Cowlitz Cogeneration project	Cowlitz	Washington	Combined	395		Weyerhaeuser
Everett Delta 1 (Preston Point)	Snohomish	Washington		496		FPL Energy
Goldendale	Klickitat	Washington	Combined	248		Calpine
Goldendale NW (The Cliffs)	Klickitat	Washington	Gas Turbine	190		Goldendale NW Alum
Longview Power Station	Cowlitz	Washington	Combined	245		Enron
Mercer Ranch	Benton	Washington	Combined	850		Cogentrix
Mint Farm	Cowlitz	Washington	Combined	286		Mirant
NW Regional Power (Creston)	Lincoln	Washington	Combined	838		Northwest Power Ent
Satsop (Grays Harbor Phase l)	Mason	Washington	Combined	650		Duke Energy NA
Satsop ll (Grays Harbor Phase ll)	Mason	Washington	Combined	600		Duke Energy NA
Sedro-Wooley	Skagit	Washington	Gas Turbine	83		Tollhouse Energy
Starbuck	Columbia	Washington	Combined	1,200		PPL Global
SUBTOTAL				11,277		

Summary of Proposed Combustion Turbine Facilities in the Pacific Northwest (cont.)

Facility	County	Location	Technology	Output (MW)	Est. Online Date	Company
Press Release Only						
Black Hills	Hill	Montana		80		Black Hills Power
Blackfeet	Glacier	Montana		160		Adair
Indigenous Global		Washington		1,000		Indigenous Global
Port Fredrickson Industrial	Pierce	Washington		324		Morgan Stanley
SUBTOTAL				1,564		
GRAND TOTAL				**26,790**		

Source: Database of Proposed Generation within the Western Electricity Coordinating Council, February 2, 2004.

1(2) As indicated in the alternatives analysis (see Section 2.4 and Appendix A of the Draft EIS), the Applicant considered the construction of a smaller facility. However, a smaller facility would not meet the requirements of reliability for steam delivery to the refinery and cost-effective power productions. Please refer to General Response A for additional information regarding an evaluation of facility size.

1(3) SCONOx control technology has been demonstrated on smaller combustion turbines (approximately 1 to 40 MW) in California and Massachusetts. To date, however, there have not been any SCONOx systems installed on large combustion turbine applications such as that proposed for this project. Additional technical uncertainties regarding the applicability of SCONOx technology to “F” class turbines have recently been raised by other permitting agencies. On May 30, 2001, the U.S. EPA Environmental Appeals Board and the California Energy Commission issued simultaneous rulings on another project; both refused to overturn a Best Available Control Technology (BACT) decision by the Shasta County Department of Resource Management Air Quality Management District that the SCONOx technology is not technically feasible for turbines of the size being considered for the proposed BP Cherry Point Cogeneration Project. In its BACT decision, the District said that several operational requirements associated with the SCONOx technology make it impractical for use as an emission control technology for “F” class turbines. It stated that all routine operating conditions were not covered in the SCONOx technology guarantee and that the guarantee would be void if water came into contact with the catalyst. Selective catalytic reduction (SCR) was the alternative BACT technology that was selected.

While it is true that the SCR system can use aqueous ammonia to control NO_x, anhydrous ammonia is proposed for economic reasons. Aqueous ammonia is approximately 20% ammonia, which would require additional quantities of ammonia to be delivered to the cogeneration facility, requiring more or larger storage tanks and additional internal piping. Because the BP Refinery currently transports, uses, stores, and internally transfers anhydrous ammonia—all within local, state, and federal guidelines—the Applicant chooses to use anhydrous ammonia in the SCR.

1(4) A discussion of the handling and storage of ammonia is presented in Sections 2.2.2 and 3.16.2 of the Draft EIS. As described in Section 3.15.2 of the Draft EIS, trucks would deliver anhydrous ammonia to the cogeneration facility approximately twice a month. Currently, ammonia is delivered to the refinery twice a year. It is anticipated that the additional ammonia needed for the SCR would be supplied by local suppliers and delivery trucks would use the same routes as used today. All ammonia delivery trucks would have to follow appropriate federal, state, and local permitting requirements. In addition, the revised Risk Management Plan required by the EPA would identify and describe actions to be taken by the refinery and public emergency response personnel in case of an accidental spill or traffic accident in which ammonia is released into the environment.

1(5) The models used for estimating the amount of secondary particulate formed did not cap the amount of ammonia available for reaction. It is assumed that sufficient ammonia was present in the airshed for the maximum amount of secondary particulate to be formed from NO_x and SO_2 emissions. The source of ammonia in the airshed (i.e., ammonia from existing industrial or agricultural sources, or ammonia from the project) did not influence the amount of secondary particulate formed.

Ammonia is recognized as a hazardous air pollutant as defined under WAC 173-460-150, and the impacts of ammonia emissions were analyzed in accordance with the requirements of Chapter 173-460 WAC. The maximum predicted concentrations were modeled and compared against the corresponding Acceptable Source Impact Level (ASIL). The ASILs are health-protective thresholds well below concentrations that are known to cause harm to human health and the environment. If concentrations are below the ASILs, no additional study is required by state or federal law. If concentrations exceed the ASILs, a “second tier” health assessment must be performed to determine if the emissions and resulting ambient concentrations will threaten human health or increase human health risks. The second tier analysis may be required to consider the impact of other existing sources of the compound on potential health risks. Because no ASILs were exceeded, additional analysis of other ammonia sources is not necessary.

1(6) Please refer to Response 1(3) of this letter for a discussion of SCONOx technology. This comment refers to a new generation of low NO_x burners appropriate for power plants that can reportedly lower NO_x emissions to below 5 ppm without causing ammonia emissions. The authors of the Final EIS assume that this improved technology is being proposed instead of the dry low NO_x burners proposed by the Applicant. Without more specific detail regarding the manufacturer and usage specifications of the <5 ppm burners, it is not possible to assess whether such technology could be applied to this size and type of generation facility. The dry low NO_x technology being proposed has been commercially available and proven effective for GE 7FA turbines. BACT for this type of project also requires NO_x emission reductions to be 2.5 ppm or lower.

1(7) Atmospheric reactions that convert ammonia, NO_x, and SO_x to secondary particulate (ammonium nitrate and ammonium sulfate) take place outside of the exhaust stacks hours to days after the NO_x and SO_x have been emitted from the facility. The reactions are controlled by time, temperature, humidity, sunlight, concentration of the reactants, and atmospheric mixing. Secondary particulate is therefore formed at great distances from the source of the pollutants.

Impacts of nitrate and sulfate deposition on soils must be evaluated in Class I areas. This evaluation was performed and results were within acceptable criteria, according to the federal land managers (see Section 3.2.3 in the Final EIS).

Neither guidelines nor thresholds for impacts from deposition to soils have been established for Class II areas. Nevertheless, the Applicant modeled the deposition rates near the project site and determined that maximum rates occur on the northern side of the facility boundary. The maximum deposition rates modeled were 167 and 187 grams/hectare/year for ammonium sulfate and ammonium nitrate, respectively. In the absence of any guidelines or regulatory criteria for the assessment of impacts, this deposition rate was compared to typical nitrogen fertilizer rates in agricultural soils. Agricultural spreading of fertilizer can vary widely depending on soil or crop type. Nitrogen is typically spread on agricultural lands at a rate of 250 pounds/acre/year. The maximum deposition rate for the project represents 0.17 pound/acre/year, which is a small amount compared to that added by agricultural soil amendment.

1(8) Please refer to Response 1(4) of this letter.

1(9) Please refer to Responses 1(3) and 1(4) of this letter.

1(10) Please refer to Response 1(4) and Section 3.16.2 of the Draft EIS regarding the transportation, handling, storage, and potential impacts resulting from a release of ammonia.

1(11) Section 3.2.1 of the Draft EIS has been revised to reflect that the proposed cogeneration facility would be subject to Title III requirements. Pertinent regulations addressing this issue include: Accidental Release Prevention and Risk Management Plan, 40 CFR 68, Chapter 90.56 RCW and Hazardous Substances/Worker Community Right to Know Act, Chapters 70.105, 70.136, and 49.70 RCW.

1(12) Section 2.4.3 of the Final EIS has been updated to include additional information about the Applicant's choice of a wet cooling system versus a dry cooling system.

In choosing wet cooling for the project, the Applicant considered the following factors: (1) availability of water supply; (2) footprint required for the cooling system; (3) impacts on project power generation efficiency; (4) impacts on visual resources; (5) noise emissions from the facility; and (6) capital cost of the cooling system.

As explained in Section 2.4.3 of the Final EIS, dry cooling was originally considered because of the restricted availability of local certificated water resources. Instead, an agreement was established among the Applicant, Alcoa Intalco Works, and the Whatcom PUD allowing once-through water used for cooling at Alcoa Intalco Works to be used as inlet water in the wet cooling system for the project. At times when Alcoa Intalco Works is not in operation, the PUD will supply the water directly to the project. It should be noted that if Alcoa Intalco Works is not in operation, the average amount of water supplied to the project would be less than the water consumed by Alcoa Intalco Works and reused by the project.

The Applicant is choosing the wet cooling system because it would require a smaller footprint for the equipment, would have less visual impact, would produce less ambient noise, would not incur a 1.6% loss in power generation efficiency, and would cost less (one-third that of a dry cooling system).

The commenter presents an extensive list of facilities that use cooling systems other than wet cooling. The commenter, however, does not explain the particular circumstances of the facilities that lead to these choices. For example, in the case of the Chehalis Generation Facility, the choice to use air cooling was made partially to avoid the cost of constructing a pipeline to withdraw and carry the water from the Chehalis River and to discharge wastewater to the City of Chehalis' water treatment system rather than to the Chehalis River.

1(13) There is no economic justification for evaluating a zero liquid discharge facility. The BP Refinery has an operating wastewater treatment facility that is capable of treating and disposing of the wastewater from the cogeneration facility. A new and separate treatment plant would not be warranted. Solid waste material from the refinery's treatment system would include small quantities of chemicals in the waste stream from the cogeneration facility; the quantity of solids attributed to the cogeneration facility would be small compared to the material currently disposed of by the refinery.

1(14) The Draft EIS states that the cogeneration facility would generate 190 gpm on average (assuming 15 cycles of concentration in the cooling tower) of non-recyclable process wastewater that would be sent to the BP Refinery's wastewater treatment system. As presented in Table 3.4-4 of the Draft EIS, the estimated concentration of trace metals and other constituents in the cogeneration facility wastewater discharge represents what is anticipated to be present after up to 15 cycles. The Draft EIS includes detailed notes for Table 3.4-4, including the source of the data used to make the concentration calculations. Many of the trace metals presented in the table were not detected. This indicates that if those metals are present in the water from the Nooksack River, they are at concentrations below the values used to derive the concentrated values presented in Table 3.4-4. Therefore, it is not anticipated that concentrating trace metals present in cogeneration facility feedwater (i.e., raw water from the Nooksack River) would produce significant concentrations of potentially toxic materials in the discharge water. Additionally, no radioactive materials will be used at the cogeneration facility, and therefore there is no reason to anticipate the presence of radioactive materials at toxic concentrations in the feedwater or discharge water.

1(15) The ISOM unit (gasoline isomerization or Clean Fuels Project). is being constructed on existing laydown areas within the refinery, not in wetlands; therefore, it is not subject to the jurisdiction of the U.S. Army Corps of Engineers (Corps) under the Clean Water Act.

BP Refinery is proposing to use the Brown Road Materials Storage Area to replace those laydown areas used for the ISOM unit. That area does have wetlands under the jurisdiction of the Corps, and the Corps is reviewing the proposal. The Brown Road Materials Storage Area is located between Alternative Cogeneration Sites 2 and 3 or Alternative Laydown Sites C and D as presented in the revised alternatives analysis (Appendix A) in the Final EIS.

It is correct that the wetland mitigation area for the Brown Road Materials Storage Area is adjacent to CMA 2, one of the wetland mitigation areas for the cogeneration facility.

1(16) Consideration of the impacts of the ISOM project has been incorporated into the analysis of cumulative impacts resulting from the proposed project. The ISOM project would cumulatively, but not significantly, add to air emissions and wetland impacts. The ISOM project is being constructed within the refinery grounds and has no wetland impacts. The Brown Road Materials Storage Area would include wetland mitigation north of Grandview Road and west of the proposed cogeneration facility mitigation areas. Discharge from the Brown Road Materials Storage Area to the wetland mitigation area would be through existing ditches within the proposed cogeneration facility laydown areas. These ditches would not be eliminated by construction of the laydown areas.

The appropriate sections of Chapter 3 have been revised to incorporate this information.

1(17) The Draft EIS states that effluent from the cogeneration facility's oil-water separator would be discharged to a final treatment and detention pond properly sized in accordance with Whatcom County and Ecology requirements, not to ponds in CMA 1. Once treated, stormwater would be routed to the wetland mitigation area.

1(18) Please refer to Response 1(16) of this letter.

1(19) Thank you for your comment. The Applicant proposes to tap into the Ferndale Natural Gas Pipeline that runs between the refinery and the proposed location of the cogeneration facility. The Ferndale Pipeline, owned and operated by BP Pipeline, Inc., originates in Sumas, Washington, near the Canadian border. The pipeline extends 30.7 miles to Ferndale. The pipeline is not dedicated or devoted to any public use but is used exclusively to transport natural gas for consumption as fuel at BP's Cherry Point Refinery and Alcoa Intalco Works. The maximum allowable operating pressure of 550 pounds per square inch gauge (psig) was authorized by the Washington Utilities and Transportation Commission (WUTC) in a waiver at the time the Ferndale Pipeline was commissioned in 1990. The pipeline was designed for Class 4 locations (a location where buildings with four or more stories aboveground are prevalent) per CFR 192 (DOT regulations) and to operate at a maximum allowable operating pressure of 1,105 psig. The pipeline operates at 550 psig.

There have been no leaks or operational failures on the Ferndale Pipeline (Walsh, pers. comm., 2004). The WUTC pipeline safety inspection staff have performed annual inspections on the pipeline since it was put in use. In March of 2000, BP inspected the pipeline using what is known as a "smart pig." One metal failure was found and repaired; two others were investigated, but no repairs were required.

BP Pipeline, Inc. is required to operate the pipeline according to applicable state and federal safety standards and regulations. Since the pipeline was installed, the regulatory agency with oversight (WUTC) has not raised questions about the pipeline's structural integrity or safety record.

1(20) Please refer to Response 1(19) of this letter.

1(21) If a pipeline incident were to occur inside the refinery boundary, the refinery's emergency response personnel would respond to the emergency. The Applicant has agreed to work with Fire District No. 7 to develop an emergency response protocol, which would be incorporated into mutual aid agreements between the two entities.

1(22) Hydrogen will be stored in pressurized cylinders near the gas turbines as shown in Table 3.16-5 of the Draft EIS. The hydrogen will be used for cooling combustion turbine blades during normal operation. An estimated 605,000 standard cubic feet of hydrogen storage is required. As mentioned in Response 1(21), specific protocols would be followed in using, storing, and transporting hydrogen and other potentially flammable materials.

1(23) State and federal laws require certain hazardous materials to be identified and quantified for local emergency response organizations. The proposed project will continue to comply with all state and federal laws concerning hazardous material transport, use, and storage.

1(24) Regardless of the current supply, demand, and future predicted market characteristics, the use of gas, its cost, and the potential for new gas reserve development or alternatives to gas as an energy source are determined by market forces and not evaluated in this EIS. An attempt to identify potential impacts resulting from further gas development in Canada would be, at best, speculative in nature, and such development would be subject to Canadian environmental review and mitigation by the appropriate Canadian regulatory agencies.

Section 3.8.4 of the Final EIS have been updated to include an analysis of cumulative impacts on regional natural gas supplies.

1(25) Thank you for your comment. Section 3.2.3 of the Final EIS has been revised to include a discussion of secondary formation of particulate matter.

1(26) PM_{10} emissions from the cooling towers will be limited to 7.2 tons per year on a rolling annual average, estimated monthly. Therefore, even though the cogeneration project may be larger than the Goldendale Energy Plant, its annual cooling tower emissions will be similar. The PM_{10} emissions from the cooling tower were included in the consideration of the project's impacts on ambient air quality and other regulated air quality values. It was determined that the project as a whole, including the cooling tower, would not violate ambient air quality standards.

Emissions from the cooling tower are expected to consist of only PM_{10}. These emissions originate from the dissolved solids contained in droplets of cooling water called "drift" that escape in the air stream exiting the cooling tower. Drift eliminators have been incorporated into the tower design to remove as many droplets as practical before the air exits the tower. A high efficiency drift eliminator with a drift rate of 0.001% is proposed for the project. Droplets that exit the tower are expected to land close to this source.

1(27) Section 3.2 of the Draft EIS addressed the formation of secondary particulate. The discussion has, however, been expanded in the Final EIS. Table 3.2-23 of the Final EIS estimates the secondary particulate that could be formed by the project and decreases in secondary particulate emissions as a result of removing the refinery boilers.

The CALPUFF model was used to assess the visibility impacts in Class I areas, as required by the PSD program. CALPUFF takes into account the formation of secondary particulate and the contribution of that particulate on visibility impacts. The federal land managers have indicated that the visibility impacts on Class I areas (see Section 3.2 3 of the Final EIS) are acceptable (Morse 2003).

Section 3.2.3 of the Final EIS has been updated to include a discussion of health impacts of fine particulate, PM_{10}, and $PM_{2.5}$ in particular. The project will not violate PM_{10} and $PM_{2.5}$ National Ambient Air Quality Standards. These standards conservatively protect human health.

1(28) The Department of Ecology, as a contractor to EFSEC, reviewed the Applicant's process wastewater characteristics and proposed treatment protocol. The primary purpose of this technical review was to identify conditions, mitigation measures, and/or wastewater treatment methods needed to meet the state water quality standards that protect marine biota in the receiving water around the refinery discharge. If the project is approved, final project-specific State Waste Discharge and National Pollutant Discharge Elimination System (NPDES) permits would specify the discharge limits of treated process wastewater (including inhibitors) and stormwater from the project. Such limits protect human health and aquatic species.

1(29) The Applicant estimates 0.7 cubic yards per day of spent cellulose filter material will be sent from the cogeneration project to the refinery's non-hazardous waste land farm. The refinery's land farm disposes of 10 to 30 cubic yards per day. Based on the maximum potential rate of generation of spent cellulose waste, the cogeneration project would increase the current land farm disposal rate at the refinery by 2.3% to 7.0%. Hazardous materials would be treated and disposed of at an approved facility.

1(30) The stormwater treatment system will be designed to meet the requirements of Whatcom County and the design standards presented in Ecology's Stormwater Management Manual for Western Washington (2000). Additionally, discharge from the oil-water separator and stormwater treatment pond will be required to meet the conditions of a NPDES and State Waste Discharge permits, which cover all discharge from the cogeneration facility to surface waters. These measures should sufficiently minimize potential impacts of stormwater runoff from the cogeneration facility and would protect all applicable state water quality standards.

1(31) The stormwater collection and treatment system is described in detail in Section 3.4 Water Quality on page 3.4-12 of the Draft EIS. As described, all stormwater runoff from the cogeneration facility, with the exception of stormwater captured in secondary containment structures for outside tanks and chemical storage areas, would be routed to the oil-water separator by the stormwater collection system. Stormwater captured in the secondary containment structures would be analyzed for the presence of fuel and chemical contaminants. If contaminants are detected, this stormwater would be routed to the refinery’s treatment system. If contaminants are not detected, this stormwater would be routed to the cogeneration facility’s stormwater treatment system, including the oil-water separator. It should be noted that some stormwater in the switchyard area will infiltrate directly into the underlying soil. Additionally, discharge from the oil-water separator and stormwater treatment pond will be required to meet the conditions of a NPDES permit, which covers all discharge from the cogeneration facility to surface waters. These measures should sufficiently minimize impacts of stormwater runoff from the cogeneration facility.

1(32) Biocides will be added to control bacteria in the cooling towers, and thereby prevent the formation of *Legionella* bacteria. A mixture of bleach (15% aqueous solution of sodium hypochlorite) and sodium bromide (40% aqueous solution) will be added to the circulating water in a ratio of 10:1. This is the same biocide formulation that is used in the existing refinery cooling towers. Generally, industrial cooling systems are less prone to bacterial formation because they operate continuously, unlike indoor heating/ventilation/air-conditioning (HVAC) systems, which have caused outbreaks of Legionnaires’ disease. Continuous operation keeps the biocides well mixed in the circulating water and reduces stagnant conditions where bacteria can develop and reproduce. This information has been incorporated into Section 3.16 of the Final EIS.

1(33) Because the comment mentions proposed transmission lines “about 3000 feet long” we assume it refers to the 230-kV double circuit line (approximately 0.8 mile long or 4,224 feet) needed to connect with Bonneville’s Custer-Intalco Transmission Line No. 2 for integration with the transmission grid. Underground construction of high voltage transmission lines tends to be much more expensive than overhead construction. It is unusual for any utility to use underground construction for 230-kV lines—the few examples cited are exceptions. Reasonable circumstances for constructing transmission lines underground would be marine crossings or dense urban areas. The additional equipment required, such as insulating fluids, high-pressure pumps, and temperature-monitoring equipment, would greatly increase costs. Also, the relative difficulty of maintaining and repairing underground transmission lines makes an underground line less reliable. Regarding the point that the new line would create an avian collision hazard, studies have found that such problems occur only in specific, localized situations where birds in flight must frequently cross a power line within their daily use area (Edison Electric Institute 1994). Although the proposed transmission line would pass through an emergent wetland, a narrow band of black cottonwood, and mixed coniferous/deciduous forest habitat used by some of the birds listed in Table 3.7-1, there is no evidence to indicate the line would intersect a major local flyway. It was also suggested the line would cause significant visual impact and increase human exposure to electromagnetic fields; however, the line would be located on unpopulated land zoned for industrial use and near industrial facilities. Finally, underground construction would cause substantially more ground disturbance than overhead construction. Underground construction is not a reasonable alternative because it offers no environmental advantages to overhead construction in this situation, would be significantly more expensive, and would be less reliable.

1(34) The estimate of pollutant emission reductions from removal of refinery boilers focused only on criteria pollutants. The ammonia emissions from operation of the project were identified in Table 3.2-13 of the Draft EIS. Secondary particulate formed by ammonia, NO_x, and SO_2 emissions was also discussed in Section 3.2 of the Draft EIS. Long range modeling of project emissions, including conversion to secondary particulate (and excluding any reductions from removal of refinery boilers), has shown that the project will not violate any U.S. or Canadian ambient air quality standards or objectives.

We assume that the commenter's statement that the project will emit as much as 1,400 tpy of secondary particulate is based on the analysis performed in the Wallula Power Project Final EIS. The Wallula Final EIS states that, theoretically, 1 ton of ammonia emissions could yield 4.6 tons of secondary particulate as ammonium nitrate. However, the Wallula Final EIS also states that the chemical fate of ammonia emissions from the plant is not well understood, and it is uncertain what fraction of the ammonia would actually react to form ammonium nitrate. As noted in Response 1(5), the Whatcom County/Lower Fraser Valley airshed is already ammonia rich because of existing industrial and agricultural activities; therefore, additional emission of ammonia from the project may not be the controlling factor in secondary particulate formation and the emissions of NO_x and SO_2 would be. Other commenters have also noted that the conversion rates used by the Applicant (much less than the theoretical stated above) could be overestimating the actual conversions.

1(35) To meet the 2005 federal standard for sulfur in gasoline, the Applicant proposes to implement a clean gasoline project at its Cherry Point Refinery in Whatcom County. The project will process light naphtha feedstocks to produce a gasoline blend that has essentially no benzene, olefins, or sulfur, and is higher in octane than its feed. The project will have a naphtha dehexanizer unit; an ISOM Hydrotreater (IHT) that includes a process heater, a naphtha hydroheater, and a BenSat unit; a Penex (isomerization) unit; connections to existing processes and changes in tank services within the refinery; and a new #2 boiler. The cumulative impacts of the ISOM project (gasoline isomerization or Clean Fuels Project) have been included in the appropriate sections of the Final EIS, with air emissions from the ISOM project identified in Section 3.2.

Please refer to Letter 12, Response 3 and Response 1(5) of this letter for an explanation of why cumulative impacts on ambient air quality from both criteria and toxic pollutants are not expected.

1(36) Regarding NO_x reductions mandated by the consent decree (*United States v BP Exploration and Oil Co.*, 2:96 CV 095 RL)[1], BP West Coast Products, LLC maintains a list of emissions sources at the refinery that are targeted for removal to comply with the emissions reductions mandated by the consent decree. According to the requirements of the decree, the list is updated annually; however, equipment may be added or removed as long as the emission reduction targets are met. At the time of Final EIS preparation, the refinery boilers were on the list of equipment targeted to be removed at the refinery to comply with the decree. Emission reduction credits (ERCs) are not being sought for the removal of the boilers. Therefore, if the boilers are still on the mandated equipment removal list when the proposed project is constructed, their removal can partially fulfill the requirements of the consent decree.

Consideration of the contribution of the BP Refinery emissions to the past non-attainment status of the Seattle area or to ambient air quality in British Columbia is outside the scope of this Final EIS.

1(37) The emission of toxic air pollutants was summarized in Table 3.2-13 of the Draft EIS. Table 3.2-13 showed all toxics for which emission increases are expected. The Applicant does not seek credits for decreases in toxic air pollutants or criteria emissions resulting from removal of the boilers at the refinery. The Applicant is not seeking to trade emissions of toxic air pollutants from the project, which underwent the full review required by WAC 173-460 without any credits for refinery reductions being taken into account. The commenter is correct that removal of the refinery boilers can also lead to a reduction in toxic air pollutant emissions. This would represent an environmental benefit. Because the primary environmental benefit for the regional airshed is associated with reductions in criteria pollutants, the benefit of reducing toxic air pollutants was not quantified.

No ERCs are being sought for the proposed project. The analysis of the environmental and health impact of emissions from the project was performed without taking into account reductions resulting from the removal of the refinery boilers. These reductions were considered only in a semi-quantitative manner regarding the regional impact of the project as a whole. All impact analyses required by state and federal regulation were performed without including the refinery reductions.

[1] See http://www.nwair.org/regulated/aop/BP/BP%20-%20Consent%20Decree%201-01.pdf

Responses to Comments in Letter 18 from Karen Kloempken, Fish and Wildlife Biologist, Department of Fish and Wildlife

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. In Section 3.7.2 of the Final EIS under the heading Wildlife and Habitat, Custer-Intalco Transmission Line No. 2, the following text will be added, "Bonneville will consult with WDFW during design of the transmission line to develop the Hydraulic Project Approval."

2. In Section 3.7.1 of the Final EIS under the heading Threatened and Endangered Species, Federally Listed Threatened Species, the following text will be added, "The WDFW Priority Habitat and Species database identifies a bald eagle nesting site within about 400 feet of the Custer-Intalco Transmission Line No. 2."

   In Section 3.7.5, Mitigation Measures, the following text will be added to the Final EIS: "Bonneville will avoid transmission line construction and maintenance activities near the known bald eagle nesting site from mid-March to mid-June."

3. Thank you for your comment. Seed mixes in disturbed areas will be determined based on coordination with federal, state, and local agencies.

Responses to Comments in Letter 19 from Trina Blake, NW Energy Coalition

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. According to a Settlement Agreement between the Applicant and Counsel for the Environment, and should the project be approved by the Governor, the Applicant shall decommission the BP Refinery's No. 1, No. 2, and No. 3 boilers within six months of the project's entry into commercial operation. Upon completion of the decommissioning, the Applicant would provide EFSEC with written notification and proof that the boilers have been decommissioned at the BP Refinery. Other stipulations of the agreement have been included in the Final EIS, Section 3.2, Mitigation Measures.

2. Without an applicable state or federal regulation requiring mitigation or reduction of CO_2 emissions[2], the EFSEC must consider proposals for CO_2 mitigation on a case-by-case basis. According to the Settlement Agreement between the Applicant and the Counsel for the Environment, BP West Coast Products, LLC will go beyond the mitigation proposal presented in the Draft EIS. Regarding the potential for facility ownership to change, the Settlement Agreement requires that the Applicant continue to offset its ownership (equity) share of the CO_2 emissions according to BP's existing, voluntary policy, and that the third party certificate holder mitigate its share according to the requirements of the Settlement Agreement described in Section 3.2.7 of the Final EIS.

3. Capacity factor is no longer a consideration in determining the amount of CO_2 emissions that have to be mitigated. If the Applicant holds an equity (ownership) interest in the project, the Applicant will offset its share in the project's emissions by reducing greenhouse gas emissions elsewhere in the Applicant's worldwide operations, consistent with its voluntary corporate policy. If a portion of the project is sold, 23% of actual emissions would be mitigated.

4. The Settlement Agreement between Applicant and the Counsel for the Environment is independent of the Oregon standard. Depending on the ownership of the project, from 23% to 100% of actual emissions must be mitigated at a cost of $0.87 per metric ton of CO_2.

5. Through the Settlement Agreement between the Applicant and the Counsel for the Environment, the payment would be increased to $0.87 per metric ton. Although the Settlement Agreement continues to endorse annual payment, the cost per metric ton is now linked to the Producer Price Index and would be adjusted annually.

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[2] House Bill 3141, signed into law on March 30, 2004, applies to proposals that submit Applications for Site Certification to EFSEC after July 1, 2004.

6. Thank you for your comment. The Settlement Agreement between the Applicant and the Counsel for the Environment does not require additional payment for administrative costs.

7. The Settlement Agreement between the Counsel for the Environment and the Applicant allows a third party (should project ownership change in the future) to choose the method of mitigation only on the share of emissions not owned by the Applicant.

8. Thank you for your comment. The Settlement Agreement between the Applicant and the Counsel for the Environment goes beyond the original proposal made by the Applicant in its Application for Site Certification and ensures substantial mitigation of CO_2 emissions.

Responses to Comments in Letter 20 from Mike Torpey, Environmental Team Lead, BP Cherry Point Cogeneration Project

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Thank you for your comment.

2. Thank you for your comment. The description of the No Action Alternative has been revised in the Final EIS. The No Action Alternative indicates that in order to meet long term regional power needs additional generation would need to be brought on line. Baseload generation would most likely be augmented by increasing the size of existing facilities or constructing new ones. It is correct that the siting of other cogeneration facilities is less likely, because in addition to access to transmission and natural gas supply services, a cogeneration developer would have to find a receptive host for produced steam. Because non-cogeneration combustion turbine projects are less fuel efficient, they would likely produce more emissions (air and water) per kilowatt hour. The impacts of this type of inefficiency have been assigned to the No Action Alternative in the respective sections of Chapter 3.

   Appropriate changes/corrections have been incorporated into the Final EIS. The project description in the Draft EIS was consistent with the Application for Site Certification and its Appendix D; therefore, the "typographical errors or correcting statements" usually reflect changes in the design of the project since the Draft EIS was prepared.

3. See specific responses below.

3(1) Thank you for your comment. The Draft EIS has been revised to reflect an 83% boiler efficiency.

3(2) Thank you for your comment. The Draft EIS has been revised to note the Bonneville right-of-way occupies 71 acres.

3(3) Thank you for your comment. A 265-horsepower, diesel-driven emergency water pump for fire suppression has been added to the list of project elements.

3(4) Thank you for your comment. Treatment facilities for boiler water have been added to the list of project elements.

3(5) Thank you for you comment. The Draft EIS has been revised to reflect this change in the project description.

3(6) Thank you for you comment. The Draft EIS has been revised to reflect this change in the project description.

3(7) Please refer to Response 2 of this letter.

3(8) Thank you for your comment. This and the following six comments relate to "issues to be resolved." Section 1.6.1 of the Draft EIS has been revised to reflect the resolution of this issue.

3(9) Thank you for your comment. The Draft EIS has been revised to reflect the resolution of this issue and change in the project description.

3(10) Thank you for you comment. Table 2-1 of the Draft EIS has been revised to reflect this change in the project description.

3(11) Thank you for you comment. Table 2-1 of the Draft EIS has been revised to reflect this change in the project description.

3(12) Thank you for you comment. The Draft EIS has been revised to reflect this change in the project description. The new substation within the refinery near the existing substation MS3 will have a kilovolt capacity of 115, not 230 kV.

3(13) Thank you for you comment. The Draft EIS has been revised to reflect this refinement of the project description. Wetland impacts from the construction of the pipeline support structure are addressed in the Section 3.5, Wetlands, of the Final EIS.

3(14) Thank you for your comment. The commenter notes the expansion or modification to the Custer-Intalco electrical transmission system will be built, owned, and operated by Bonneville. The types of transmission structures to be erected are identified in Figure 1-2 and described in Section 2.2.2 of the Draft EIS. The following sentence has been inserted in the Final EIS under the heading Option 2b - New Transmission Line with Monopole Towers, "Under either Option 2a or 2b, the specific number of structures and their locations, as well as specific access road needs, will not be known until further design is completed."

3(15) The bullet has been revised to reflect mitigation measures presented in the revised Application for Site Certification.

3(16) Thank you for your comment.

3(17) Table 1-2 of the Draft EIS has been revised to reflect this addition.

3(18) Thank you for your comment.

3(19) Thank you for your comment. According to the Stormwater Management Manual for Western Washington (Ecology 2000), Best Management Practice (BMP) C106 recommends the use of wheel washers for construction sites when a stabilized construction entrance is not preventing sediment from being tracked onto pavement.

3(20) Thank you for your comment.

3(21) Table 1-2 of the Draft EIS as been revised to reflect this addition.

3(22) Thank you for your comment.

3(23) Thank you for your comment. The recommended mitigation measure has been incorporated into list of the Applicant's proposed mitigation measures.

3(24) The EIS has been revised to reflect this correction.

3(25) For information on the agreed upon traffic mitigation after the start of construction, please refer to Letter 8, Response 1.

3(26) The existence of the 71-acre Bonneville right-of-way as part of the project has been noted in the Final EIS.

3(27) Thank you for your comment. The pump has been added to the equipment list for the cogeneration facility in the Final EIS.

3(28) Thank you for your comment. Water treatment facilities have been added to the referenced list.

3(29) Thank you for your comment. The Draft EIS has been revised to reflect this change in the project description.

3(30) Thank you for your comment. The Draft EIS has been revised to reflect this change in the list of proposed equipment.

3(31) Thank you for your comment. Table 2-1 of the Draft EIS has been revised to reflect uninterruptible power supply.

3(32) Thank you for your comment. The Draft EIS has been revised to reflect this change in the project description.

3(33) Thank you for your comment.

3(34) Thank you for your comment. The Draft EIS has been revised to reflect this change in the project description.

3(35) The Draft EIS has been revised to reflect this clarification. Conditions set through the National Pollutant Discharge Elimination System (NPDES) permit, BMPs, and other permit requirements are expected to protect state water quality standards by limiting potential contamination of stormwater and protecting groundwater quality during construction and operations.

3(36) Thank you for your comment. According to the draft NPDES permit, "stormwater that has the potential to collect process chemicals and lube oils will be routed to the process wastewater system."

3(37) Section 2.2.2, Project Description, and Section 3.3.2 of the Draft EIS have been revised to reflect this additional information.

3(38) The Draft EIS has been revised to reflect that Compensatory Mitigation Area (CMA) 2 will receive stormwater discharge from the cogeneration facility.

3(39) BP's application indicates that Access Road 3 would meet Washington State Department of Transportation (WSDOT) and emergency vehicle requirements. According to Section 2.11 of Appendix D in the application, roadwork outside the plant boundary would be constructed in accordance with the WSDOT and emergency vehicle requirements. The Applicant did not support the suggested change in Access Road 3 construction standards with a revision to the application or a commitment during the adjudicative hearings.

3(40) Thank you for your comment. The text in the Draft EIS has been revised to reflect that all major equipment and buildings, including the steam generator, will be on piles.

3(41) Section 2.2.3 of the Draft EIS has been revised to reflect this new information.

3(42) Section 2.2.3 of the Draft EIS has been revised to reflect this new information.

3(43) Section 2.2.3 of the Draft EIS has been revised to reflect that the right-of-way will not exceed 150 feet in width.

3(44) Section 2.2.4 of the Draft EIS has been revised to reflect this clarification.

3(45) Thank you for your comment. The EIS has been revised to reflect this information.

3(46) The Draft EIS has been revised to more accurately reflect the Application for Site Certification's mitigation requirements if contaminated soils are found during construction.

3(47) Table 3.2-1 of the Draft EIS has been revised to reflect this clarification.

3(48) Table 3.2-1 of the Draft EIS has been revised to reflect this clarification.

3(49) Section 3.2.3 of the Draft EIS has been revised to reflect this clarification.

3(50) Section 3.2.3 of the Draft EIS has been revised to reflect this clarification.

3(51) Section 3.2.3 of the Draft EIS has been revised to reflect this clarification.

3(52) Section 3.2.3 of the Draft EIS has been revised to reflect this clarification.

3(53) Section 3.2 of the Draft EIS has been updated to reflect that no criteria pollutant emission concentrations exceed the Class II Significant Impact Levels (SILs).

3(54) Section 3.2 in the Final EIS has been updated to reflect that no criteria pollutant emission concentrations exceed the Class I SILs.

3(55) The discussion of estimated emissions from the project, including emission reductions resulting from refinery boiler removal and other adjustments, has been revised for more clarity. The correction has been made.

3(56) Secondary particulate conversions based on molecular weights have been incorporated into Section 3.2.

3(57) The Final EIS reflects the statement in the Application for Site Certification (Volume 1, Section 3.2.3.2) that, "icing is not expected to occur."

3(58) The Draft EIS has been revised to state that, excluding those projects that have received certification from EFSEC, no currently permitted facilities are subject to greenhouse gas mitigation requirements in Washington State.

3(59) The No Action Alternative in Section 3.2 of the Draft EIS has been revised to reflect that if other natural gas–fired plants are built to meet regional electric demand, they would not likely be cogeneration facilities and would likely produce energy less efficiently than the proposed project. This would result in higher criteria pollutant and greenhouse gas emissions per kilowatt hour produced.

3(60) Please refer to Response 3(59) of this letter. The tonnage of CO_2 emission reductions was corrected in the Final EIS.

3(61) The Department of Energy (DOE) recognizes that natural gas leaks occur in natural gas transmission systems. The Final EIS estimates the resulting greenhouse gas emissions that could occur based on the DOE emission factors.

3(62) The Phase I study (Bonneville 2001a) went as far as identifying where impacts might occur in the northwest region assuming all the facilities considered became operational. The Phase I study did not attempt to identify which facilities caused the potential impacts identified. The purpose of the Phase II study for each specific project being proposed (i.e., the BP Cherry Point Cogeneration Project) was to refine the analysis of regional impacts and determine to what degree the impacts could be attributable to that specific facility. As indicated in the Final EIS, the Phase II study conducted for the proposed cogeneration project concluded that the project would not significantly contribute to regional haze at any of the Class I areas within the Bonneville service area, the Columbia River Gorge National Scenic Area, or the Mt. Baker Wilderness when the facilities considered in this analysis are fired by natural gas. During periods of oil firing during a winter simulation by other facilities in the study group, the project's contributions are not significant on any of the six days when the baseline group's combined change in extinction is greater than 10% in Mt. Rainier National Park. (Extinction is a coefficient used to quantify how pollutants in the atmosphere reduce visual range.)

3(63) Thank you for your comment. The correction has been made in Section 3.2 of the Final EIS.

3(64) Please refer to Response 3(62) of this letter.

3(65) The statement has been revised to reflect that the production of greenhouse gases could be reduced if operation of the BP Cogeneration Facility displaces the operation of other less efficient facilities that emit more greenhouse gases per kilowatt-hour.

3(66) Table 3.2-28 has been revised to reflect this clarification.

3(67) Table 3.2-29 has been revised to reflect this clarification.

3(68) Table 3.2-29 has been revised to reflect this clarification.

3(69) The mitigation measure has been revised in the Final EIS.

3(70) Section 3.2.3 of the Draft EIS has been revised to reflect this clarification.

3(71) Section 3.2.8 of the Draft EIS has been revised to reflect that the proposed cogeneration facility would have a minimal impact on air quality and would not violate any ambient air quality standards or objectives, or other regulatory air quality values.

3(72) Thank you for your comment. According to the Stormwater Management Manual for Western Washington (Ecology 2000), Best Management Practice C162 specifically recommends avoiding land disturbance activities during rainy periods.

3(73) Please refer to Response 3(72) of this letter.

3(74) Based on the contour information available at this time, it appears the project will intercept the low spot in the wetland. Using the 1-foot contours to fine tune the ditch design is a good first step. It is the opinion of the Corps of Engineers that there should be no perimeter ditch within the wetland or buffer to minimize the potential for draining Wetland C (Romano, pers. comm., 2004).

3(75) The text of the Draft EIS has been revised to reflect this correction.

3(76) The application indicates sanitary waste discharge from the cogeneration project would be routed to the PUD's wastewater treatment plant for treatment and discharge to the Strait of Georgia. The Applicant did not support this suggested change with a revision to the application or a commitment during the adjudicative hearings.

3(77) Thank you for your comment. The Draft EIS has been revised to reflect this clarification. Please refer also to Response 3(35) of this letter.

3(78) The text of the Draft EIS has been revised to reflect this correction.

3(79) A map provided by Whatcom County (Olson, pers. comm., 2004) depicts most of the western half of Section 8 (east of Blaine Road between Grandview and Aldergrove) as "open space agriculture." This would include the refinery interface area. This is not a zoning designation, but rather a Department of Revenue designation for current use taxation valuation.

3(80) The text of the Draft EIS has been revised to reflect this correction.

3(81) The text of the Draft EIS has been revised to reflect this correction.

3(82) Comment acknowledged. As noted in Section 3.4.4.2 of the revised Application for Site Certification, "all equipment should be cleaned before leaving the site." The Draft EIS text was revised to read, "to minimize and control the spread of noxious weed species, all-wheeled vehicles would be cleaned if they cross disturbed or exposed soil areas during construction of the proposed project."

3(83) The Draft EIS has been revised to reflect that a person's perception of a 3- to 5-dBA change in noise levels may vary with the environmental context.

3(84) The commenter is correct, and the statement in Section 3.9-6 of the Draft EIS has been removed.

3(85) The commenter is correct, and Table 3.9-5 of the Draft EIS has been revised.

3(86) The construction mitigation measure list has been revised.

3(87) The construction mitigation measure list has been revised.

3(88) Thank you for your comment. The correction has been made in the Final EIS.

3(89) The text of the Draft EIS has been revised to reflect this correction.

3(90) The Corps of Engineers and the State Historic Preservation Office (SHPO) concur with the results of the archaeological survey conducted near detention pond 2, the interconnecting pipeway, and Access Road 3. In a letter to the Corps, SHPO agreed with the definition of the Area of Potential Effect (APE) and concurred with the Corps' recommendation of Finding of No Historic Properties.

In conformance with Section 106 of the National Historic Preservation Act, the Corps identified and listed conditions in its 404 permit. SHPO also concurred with these conditions, which the Applicant would be required to comply with during construction of the proposed project.

3(91) The commenter is correct. Note 2 has been corrected in the Final EIS.

3(92) The text of the Draft EIS has been revised to reflect this correction.

3(93) The text of the Draft EIS has been revised to reflect this correction.

3(94) The text of the Draft EIS has been revised to reflect this correction

3(95) The text of the Draft EIS has been revised to reflect this correction.

3(96) Thank you for your comment. Although the use of waterborne transportation (barge) to bring heavy equipment to the site was identified in the Application for Site Certification, correspondence dated May 30, 2003, from the Applicant specifically states a barge would not be used. Therefore, the Applicant does not address potential landing impacts in the nearshore, road impacts from heavy equipment, road conflicts on public roads, or other issues. According to the Applicant, barge landings would require a number of authorizations for which analyses have not been produced. At this time, barge transport of equipment is not considered viable.

3(97) The text of the Draft EIS has been revised to reflect this correction.

3(98) The text of the Draft EIS has been revised to reflect this correction. Please refer to Response 3(25) of this letter.

3(99) Reference to the Health and Safety Plan and the Emergency and Security Plan has been revised.

3(100) The text of the Draft EIS has been revised to reflect this correction.

Responses to Comments in Letter 21 from Susan Meyer, Wetland Specialist, Department of Ecology

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Thank you for your comment. Section 3.5.2, Custer-Intalco Transmission Line No. 2, of the Draft EIS acknowledges that if the new transmission line cannot avoid wetlands, wetland delineations would need to be performed before wetland impacts can be quantified and wetland permits can be issued. The Bonneville Record of Decision would include conditions if towers need to be constructed in the right-of-way. These conditions would be that detailed wetland delineations, impact assessments, and mitigation design and monitoring plans will be completed concurrent with the proposed project.

2. Thank you for your comment. As noted in Section 3.4.5 of the Draft EIS, EFSEC has developed appropriate process wastewater and stormwater permits that include both effluent standards and a monitoring schedule for stormwater discharge from the cogeneration facility. Table 3.4-7 of the Draft EIS identifies the effluent limitations.

3. Thank you for your comment. If a recommendation for approval is made to the governor, EFSEC would develop a Section 401 water quality certification that would require submittal of a final Wetland Mitigation Plan for review by EFSEC and its Ecology contractors. In addition to detailed grading and planting plans, the final mitigation plan would include monitoring and contingency plans and all other elements recommended by existing, applicable Ecology guidance.

4. Figure 3.5-2 in Section 3.5, Wetlands, of the Draft EIS is not intended to depict wetlands. It is a map of vegetation types. Reference to wetlands has been removed from this figure. Wetland communities are accurately displayed in Figure 3.5-1 of the Draft EIS.

Responses to Comments in Letter 22 from M. D. Nassichuk, Manager, Pollution Prevention and Assessment, Environment Canada

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Section 3.2.3 of the Draft EIS has been updated to include a discussion of the potential health impacts of $PM_{2.5}$.

2. Section 3.2 of the Draft EIS has been updated to include a more thorough analysis of potential ambient concentrations of particulate matter and $PM_{2.5}$. As noted in Letter 12, Response 1, it was conservatively assumed that all particulate matter emissions were less than 2.5 microns in size.

3. Section 3.2 of the Draft EIS has been updated to include modeling of long range impacts of particulate emissions that include secondary particulate. Long range ambient air quality concentrations were assessed using the CALPUFF model.

4. Section 3.2 of the Draft EIS has been updated to include the impacts of start-up scenarios.

5. In a Settlement Agreement with the Counsel for the Environment, the Applicant has committed to remove the refinery boilers if the cogeneration project is constructed and begins operation.

6. For the review of air emissions in the scope of a permitting decision, state and federal regulations require an assessment of impacts on ambient air quality and rely only on tonnage increases as thresholds for levels of review detail. The annual mass emissions were relied on to determine that Prevention of Significant Deterioration review was applicable, and these emissions were input as applicable into the dispersion models.

   In response to this comment, the percentage increase in the Whatcom County and Lower Fraser Valley airsheds, for which the project would be responsible, was calculated based on the data in the Greater Vancouver Regional District's 2003 Forecast and Backcast of the 200 Emissions Inventory for the Lower Fraser Valley Airshed 1985-2000. The results are shown in the table below.

Annual Mass Emissions

Emissions Source	Pollutant						
	CO	**NO_x**	**VOC**	**SO_x**	**PM_{10}**	**$PM_{2.5}$**	**NH_3**
Whatcom County							
Total metric tons	114,654	17,396	40,283	10,063	1,542	2,536	3,490
Lower Fraser Valley							
Total metric tons	481,933	99,897	111,196	18,769	15,364	8,964	18,003
Sum of both airsheds, metric tons	596,587	117,293	151,479	28,832	16,906	11,500	21,493
BP Cogen/Refinery							
Max emissions, metric tons[1]	143.2	211.8	38.4	46.3	237.5	237.5	157.2
Expected emissions, metric tons[2]	73.7	164.4	25.0	45.0	85.3	85.3	157.2
Refinery reductions, metric tons	-49.0	-453.1	-2.7	-6.4	-9.1	-9.1	0.0
% of Whatcom County Emissions							
Maximum BP Cogen emissions	0.1	1.2	0.1	0.5	15.4	9.4	4.5
Expected BP Cogen Emissions	0.1	0.9	0.1	0.4	5.5	3.4	4.5
BP Refinery reductions	0.0	-2.6	0.0	-0.1	-0.6	-0.4	0
% of Whatcom County and Lower Fraser Valley Airshed Emissions							
Maximum BP Cogen emissions	0.02	0.18	0.03	0.16	1.41	2.07	0.73
Expected BP Cogen emissions	0.01	0.14	0.02	0.16	0.50	0.74	0.73
BP Refinery reductions	-0.01	-0.39	0.00	-0.02	-0.05	-0.08	0.00

1. Maximum emissions used for regulatory purposes.
2. Expected emissions include refinery boiler reductions.

7. See specific responses below.

7(1) The cogeneration project and the refinery boilers are two technologically different processes, constructed and operated for different reasons. The refinery boilers produce steam only for the refinery and are not designed or operated to produce electricity. The technology for heat production in the boilers is notably different the from combustion turbine technology being proposed for the cogeneration project, and it is therefore normal for the two processes to have different levels of emissions. It is beyond the scope of this EIS to evaluate why refinery boiler emissions are different from those of the project.

7(2) The Draft EIS has been updated to indicate that the conversion rates used by the Applicant for the long range impact of fine particulate in the airshed represent the higher end of supportable data. The quoted conversion rates (20% for SO_2 and 33% for NO_x) could be achieved under low dispersion conditions, when the maximum impacts could be expected to occur. In general, low dispersion conditions (i.e., lower wind speeds) are usually associated with higher relative humidities when water is present, resulting in the higher conversion rates.

7(3) The per-ton conversion analysis has been corrected. Mass of converted particulate is calculated based on stochiometry.

7(4) Table 3.2-8 of the Draft EIS has the correct data. Table 3.2-9 has been updated accordingly.

7(5) The footnote in Table 3.2-15 has been revised to indicate the maximum $PM_{2.5}$ emissions.

7(6) Thank you for your comment. The net regional change in PM_{10} emissions has been corrected.

7(7) Thank you for your comment. Table 3.2-23 has been simplified.

7(8) Thank you for your comment. The most recent air quality report (Greater Vancouver Regional District 2003) indicates that recent air quality trends in the Lower Fraser Valley have not changed significantly from data collected in the previous year.

Responses to Comments in Letter 23 from Mary C. Barrett, Senior Assistant Attorney General

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. At this time, the Applicant would be the sole owner and operator of the project. If the project does change ownership, EFSEC would be responsible for reviewing and approving this change. The Applicant is working with TransCanada to develop the project, but there is no official commercial agreement between the two entities. Any new owner of the facility, TransCanada or any another developer, would be required to comply with the Site Certification Agreement.

2. Please refer to Response 1 of this letter.

3. Bonneville does not now intend to purchase power from the BP Cherry Point Cogeneration Project. The power would be available to customers that are connected to the Bonneville system.

4. Please refer to Response 1 of this letter.

5. Regarding the supply of electrical energy, the Western Electricity Coordinating Council (WECC) has concluded that projected reserves are expected to be adequate through 2012, assuming that approximately 32,300 MW of planned new generation will be constructed and sufficient energy will be available for peak demands. The WECC has determined that capacity adequacy may become dependent on Pacific Northwest hydroelectric conditions after 2008.

   Both the WECC and the Northwest Air Pollution Authority (NWPCC) include existing generation, renewables, and conservation in their forecasts.

   The NWPCC's long-term forecast reflects, "estimates of future demand unreduced for conservation savings beyond what would be induced by consumer responses to price changes." (NWPCC 2003, p. 4).

   The Northwest Power Pool comprises all or major portions of the states of Idaho, Montana, Nevada, Oregon, Utah, Washington, and Wyoming; a small portion of Northern California; and the Canadian provinces of British Columbia and Alberta. From 2003 through 2012, peak demand and annual energy requirements are projected to grow at annual compound rates of 1.6% and 1.7%, respectively. With a large percentage of hydro-generation in the region, the ability to meet peak demand is expected to be adequate for the next 10 years. Capacity margins for this winter peaking area range between 23.4% and 29.6% for the next 10 years.

   WECC's 2002-2012 10-year Coordinated Plan Summary updates the load growth forecast for the Northwest Power Pool Area. It states, "for the period from 2003 through

2012, peak demand and annual energy requirements are projected to grow at annual compound rates of 1.6 percent and 1.7 percent, respectively.” (WECC 2002, p. 10). Section 1.2.2 of the Draft EIS has been revised to include the more recent estimates. The WECC report projects generation additions in the Northwest Power Pool Area totaling 11,863 MW from 2003 through 2012, including 8,753 MW combined-cycle combustion turbine, 971 MW hydro, 105 MW geothermal, and 87 MW “other.” The WECC report does not identify conservation resources.

The U.S. Department of Energy (2004) in its Annual Energy Outlook 2004 with Projections to 2025, referred to as the *AEO2004* report, projects, “continued saturation of electric appliances, installation of more efficient equipment, and the promulgation of efficiency standards are expected to hold growth in electricity sales to an average of 1.8 percent per year between 2002 and 2025.” Section 1.2.2 of the Draft EIS has been revised to include the more recent estimate.

The report continues, “changing consumer markets could mitigate the slowing of electricity demand growth seen in the *AEO2004* projections. New electric appliances are introduced frequently. If new uses of electricity are more substantial than expected, they could offset some or all of the projected efficiency gains.”

AEO2004 also projects generation capacity additions: “With growing demand after 2010, 356 gigawatts of new generating capacity (including end-use combined heat and power) will be needed by 2025, with about half coming on line between 2016 and 2025. Of the new capacity, nearly 62 percent is projected to be natural-gas-fired combined-cycle, combustion turbine, or distributed generation technology.” Regarding renewable generation, *AEO2004* projects, “renewable technologies account for just over 5 percent of expected capacity expansion by 2025—primarily wind and biomass units.”

Regarding renewable generation technologies, “*AEO2004* projects significant increases in electricity generation from both wind and geothermal power. From 4.8 gigawatts in 2002, total wind capacity is projected to increase to 8.0 gigawatts in 2010 and 16.0 gigawatts in 2025. Generation from wind capacity is projected to increase from about 11 billion kilowatt-hours in 2002 (0.3 percent of generation) to 53 billion in 2025 (0.9 percent). Nevertheless, the mid-term prospects for wind power are uncertain, depending on future cost and performance, transmission availability, extension of the federal production tax credit after 2003, other incentives, energy security, public interest, and environmental preferences. Geothermal output, all located in the West, is projected to increase from 13 billion kilowatt-hours in 2002 (0.3 percent of generation) to 47 billion in 2025 (0.8 percent).

“Generation from municipal solid waste and landfill gas is projected to increase by nearly 9 billion kilowatt-hours, to about 31 billion kilowatt-hours (0.5 percent of generation) in 2025. No new waste-burning capacity is expected to be added in the forecast. Solar technologies are not expected to make significant contributions to U.S. grid-connected electricity supply through 2025. In total, grid-connected photovoltaic and solar thermal generators together provided about 0.6 billion kilowatt-hours of electricity generation in

2002 (0.02 percent of generation), and they are projected to supply nearly 5 billion kilowatt-hours (0.08 percent) in 2025."

6. The description of the No Action Alternative in Section 1.4 of the Draft EIS indicates that none of the environmental impacts resulting from construction or operation of the project would occur, and this includes no incremental increase in greenhouse gas emissions. Section 3.2.4 of the Draft EIS has been revised to better describe the continued impacts on air quality associated with no action.

7. While Ecology does address water quality impacts through its regulation of the National Pollutant Discharge Elimination System (NPDES) permit for the refinery, EFSEC must also address impacts as part of the NPDES permit for the cogeneration facility. Water quality impacts are discussed in the Draft EIS in Section 3.4, Water Quality, and the effects of those impacts are discussed in Section 3.7, Vegetation, Wildlife, and Fisheries. The cogeneration facility will represent an estimated 8% increase in discharge from the refinery outfall, which is within the variability of existing discharge rates from the refinery. It should also be noted, as discussed in Section 3.4.1 of the Draft EIS, "the refinery uses approximately 50% of the organic and hydraulic capacity of the wastewater treatment system."

   Increases in temperature and salinity have been modeled as insignificant (BP 2002). Kyte (Prefiled Testimony, Exhibits 27.0 and 27R.0) testified that while the dilutions at the Zone of Initial Dilution and the chronic dilution zone required by the refinery's existing NPDES permit were 28:1 and 157:1, respectively, in actuality they have been shown to be 144:1 and 1709:1. Given the low level of biological effect reported at the outfall under present conditions, it is unlikely the cogeneration facility will have any measurable effect on marine life.

   The impact of wastewater discharge from the cogeneration project on state water quality standards was reviewed as part of the State Waste Discharge and NPDES permits developed for the cogeneration project. This review concluded that the discharge would not violate state water quality standards.

8. The Application under review is, and always has been, submitted solely by BP West Coast Products, LLC. If the project is approved, all permits and certifications would be issued to BP West Coast Products, LLC. If BP West Coast Products, LLC decides to sell part or all of the project, that transaction would be subject to review requirements established in EFSEC laws and rules. The Settlement Agreement with the Counsel for the Environment addresses how new ownership of the project would be addressed for mitigation conditions associated with greenhouse gas emissions. The new owner would have to comply with the requirements of the Site Certification Agreement issued to the project.

9. Section 1.8.1 of the Draft EIS has been revised to reflect the impacts of the proposal. The discussion of impacts from global warming in the Pacific Northwest has also been augmented in Section 3.2 of the Final EIS.

10. Section 1.8.2 of the Draft EIS has been revised to reflect that the Applicant is committed to shutting down three refinery boilers if the cogeneration facility is constructed and operated.

11. Ammonia emissions were analyzed per the requirements of Chapter 173-460 WAC. Ammonia emissions are regulated as a toxic air pollutant in Washington State. Ammonia emissions as a result of "slip" were modeled and compared against the appropriate Acceptable Source Impact Level (see Table 3.2-14 of the Final EIS). The ASIL is a level of concern that conservatively protects human health and the environment. Best Available Control Technology for ammonia slip is to control emissions below a specified target level, in this case 5 ppm.

12. The Applicant used the EPA test method for PM_{10} only in estimating the actual emissions that might occur from the project. This estimate of actual emissions was used to assess the likely long range impact on the airshed. The test method was not used for regulatory review of the air emissions or for determining compliance with U.S. or Canadian ambient air quality standards.

13. The discussion in Section 3.2.5 of the Draft EIS has been revised to include specific impacts from global warming that might occur in the Pacific Northwest.

14. As noted in Response 12 of this letter, the corrections to the EPA test method for primary PM_{10} emissions were not used to determine the compliance of the project with the Prevention of Significant Deterioration (PSD) and new source review requirements. The analysis of secondary particulate formation is required to assess the impacts on visibility and haze in federally protected Class I areas. The analysis was based on maximum potential emissions from the cogeneration project and did not include any adjustments for primary particulate test method. Additional modeling (not required by the PSD and new source review programs) was performed to determine the long range impact of particulate emissions; results are shown in Appendix B of this Final EIS. Exhibit 22.2, Page 2 in Appendix B shows the predicted PM_{10} concentrations for potential maximum annual emissions excluding any refinery reductions or test method adjustments. Table 3.2-23 of the Draft EIS has been revised to reflect the impacts on regional particulate matter emissions with and without the test method adjustment.

15. Please refer to Response 7 of this letter. The diffuser was inspected in August 2003. A diffuser inspection was a requirement of the refinery NPDES permit. A video was taken and a report was written and sent to the Department of Ecology.

Responses to Comments in Letter 24 from Ken Cameron, Manager, Policy and Planning, Greater Vancouver Regional District, Canada

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Additional information regarding the health effects of $PM_{2.5}$ has been added to Section 3.2 of the Final EIS.

2. Modeling of long range emissions without refinery reductions or "adjustments" for test methods to assess potential actual emissions has been included in the Final EIS (see Section 3.2). For regulatory purposes, test method and other adjustments were not considered.

3. Please refer to Letter 22, Response 7(2).

4. Section 3.2 of the Final EIS describes additional long range modeling data, which include the Canadian airshed. The modeling includes conversion to secondary particulate. The data presented in the Draft EIS were based on estimates performed with the Industrial Source Complex (ISC) Prime model; it included primary and secondary particulate by adding 20% of the sulfur emissions to the particulate matter emissions. This represented the worst-case scenario. Primary and secondary particulate were also modeled with the CALPUFF model for the annual averaging time (see isopleths in Appendix B of this Final EIS).

5. A discussion of the relationship between ammonia and secondary particulate has been included in Section 3.2 of the Final EIS. Regarding the reporting of maximum predicted ammonia concentrations in Canada, ammonia emissions from the project were reviewed under the requirements of Chapter 173-460 WAC, which considers ammonia to be a toxic air pollutant. The Applicant used a Gaussian dispersion model (ISC Prime) to determine the maximum concentration of this pollutant (reported in Table 3.2-14 of the Final EIS) and found that the resulting concentration was well below the applicable Acceptable Source Impact Level (ASIL). The ISC Prime model is used to assess impacts within a 50-km range of the source. Therefore, maximum modeled ambient concentrations in Canada would also be less than the maximum value reported (2.8 $\mu g/m^3$, 24-hour average).

6. Maximum ambient concentrations resulting from various modes of facility startup are described in Section 3.2 of the Final EIS.

7. Please refer to Letter 22, Response 6.

8. Please refer to Letter 22, Response 5. The Applicant is not seeking credit for refinery emissions reductions for regulatory purposes. Therefore, even though the removal of the refinery boilers will benefit ambient air quality concentrations, that benefit cannot be taken into account; for regulatory purposes, the analysis of environmental impact is based on maximum emissions from the cogeneration project. However, the Applicant has made

certain assumptions regarding what the expected benefit might be and has evaluated the long range impact on resulting ambient air quality. Appendix A in this Final EIS shows isopleths for criteria pollutants, which take into account refinery reductions.

9. The Applicant has demonstrated that particulate matter (PM) emissions, including particulate matter less than 2.5 microns, meet both U.S. and Canadian regulatory standards. The Applicant is using Best Available Control Technology (BACT) to control PM emissions, represented by the combustion of natural gas only in the combustion turbines. Under state and federal laws and regulations, compliance with ambient air quality standards in an attainment area and application of BACT for emission control are considered appropriate mitigation of impacts.

10. Pursuant to an Agreement with the Counsel for the Environment, the Applicant's proposal for greenhouse gas mitigation has been modified and now requires additional measures. As described in Section 3.2 of the Final EIS, the mitigation plan requires formal reporting of offsets that have been achieved and encourages projects in the Whatcom County area.

11. Thank you for your analysis and comment. It should be noted that the adjustments to maximum potential emissions were not considered for regulatory purposes. The intent was to estimate the impacts of actual emissions on the airshed. Please refer also to Letter 23, Responses 12 and 14.

12. Thank you for your comment. It has been conservatively assumed that all PM is emitted as $PM_{2.5}$. Letter 22, Response 6 addresses the percentage of BP's Cherry Point Refinery contribution of emission to the Whatcom County and Fraser Valley airsheds.

13. The particulate matter adjustments were not taken into account for regulatory purposes. The intent was to estimate the impacts of actual emissions on the airshed. Through a Settlement Agreement with the Counsel for the Environment, the Applicant has committed to remove the refinery boilers if the cogeneration project is constructed and operated.

14. Please refer to Letter 22, Response 7(2).

15. Thank you for your comment.

16. Isopleths depicting the impact on ambient air concentrations of particulate matter, averaged over 24 hours, have been added to Appendix B of this Final EIS. These isopleths include a 20% conversion to secondary particulate and do not take into account refinery emissions reductions.

17. The evaluation of impacts on ambient concentrations of ozone are only required when the proposed facility is in an area designated as non-attainment for ozone. In such a case, state and federal regulations consider nitrogen oxides (NO_x) and volatile organic

compound (VOC) emissions as ozone precursors. Whatcom County is in an attainment area for all criteria pollutants, including ozone.

18. Impacts on ambient air quality from startup of the facility have been added to Section 3.2 of the Final EIS.

19. A discussion of the impacts of particulate matter on human health has been added to Section 3.2 of the Final EIS.

20. Please refer to Letter 24, Response 9.

21. Selective catalytic reduction (SCR) has been the technology of choice for controlling NO_x emissions for this type of power generation facility. SCR meets the three BACT criteria that are required under the Prevention of Significant Deterioration (PSD) program: (1) the most stringent form of emissions reduction technology possible will be used; (2) the technology is technically feasible, and (3) the technology is economically justifiable. Although other non-ammonia-based technologies exist (XONON and SCONOx for example), neither of these has been demonstrated as technologically possible for the size of combustion turbine project being proposed. To reduce collateral effects, ammonia emissions will be limited to no more than 5 ppm.

    Regarding the toxic effects of ammonia emissions, EFSEC requires an ambient air quality analysis of toxic air pollutant emissions in accordance with WAC 173-460 Controls for New Sources of Toxic Air Pollutants. The toxic air pollutants are evaluated for both acute (24-hour) and chronic (annual) effects as required by the regulation. The quantities of all toxic air pollutants known to be emitted from the turbines and duct burners, including ammonia, were estimated and screened against the small quantity emission rates in WAC 173-460. Ammonia did not exceed the applicable Ambient Screening Impact Level (ASIL), and therefore no adverse health impacts are expected to occur from the emissions of this pollutant. The maximum ammonia concentration in Canada was determined to be 1.1 $\mu g/m^3$.

22. Please refer to Letter 22, Response 5.

23. Please refer to Letter 24, Response 9. There is no regulatory basis for requiring an offset of emissions in an area that is designated “attainment.” The proponent of the Sumas Energy 2 Project offered to voluntarily offset PM emissions, and EFSEC included this as a requirement in that project’s Site Certification Agreement.

24. Please refer to Letter 24, Response 10.

25. Regarding the emission of particulate matter, although the tons per year emitted represents a large number, the impact on ambient air quality and the environment is not deemed significantly adverse. Emissions of all air pollutants meet both U.S. and Canadian regulatory standards and guidelines. Regarding greenhouse gas emissions, the Applicant has proposed a plan that would mitigate 23% of CO_2 emissions.

26. Thank you for your comment. The table has been revised in the Final EIS.

27. Air Quality Index (AQI) hours data for 2001 have been added to Table 3.2-5 in the Final EIS. In 2002, the Greater Vancouver Regional District discontinued the practice of providing the data in the form presented in Table 3.2-5. In 2001, air quality in the district was measured as “good” 98.4% of the time, with “fair” and “poor” readings occurring 1.6% and less than 0.1% of the time, respectively. These readings are equivalent to or better than conditions recorded during the past few years. During 2001, one air quality advisory was issued. During 2002, air quality was reported as “good” 97.4% of the time, with “fair” and “poor” readings occurring 2.6% and less than 0.1% of the time, respectively. These readings are equivalent to or slightly worse than conditions recorded during the past few years. No air quality advisories were issued in 2002.

28. Table 3.2-8 of the Draft EIS had the correct data. Table 3.2-9 has been updated accordingly.

29. The footnote to Table 3.2-15 has been revised to indicate that the maximum concentrations of $PM_{2.5}$ are equal to the maximum concentrations of PM_{10}. The concentrations for $PM_{2.5}$ in Table 3.2-16 are the maximum concentrations, and the table heading has been revised to reflect this. Table 3.2-20 of the Final EIS has been corrected and reorganized for clarity.

30. Table 3.2-23 of the Final EIS has been revised for clarity. The data have been corrected to reflect molecular weights of compounds.

Responses to Comments in Letter 25 from David M. Grant,
Deputy Prosecuting Attorney, Whatcom County

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Dave Enger, a traffic engineer with Traffic Planning and Engineering Inc., analyzed the intersection of Grandview Road and Vista Road with the proposed Delta Tech Industrial Park, including the proposed closure of the southern segment of Delta Line Road. Based on Mr. Enger's results, if the proposed Delta Tech Industrial Park is open prior to the start of construction of the cogeneration facility and the southern portion of Delta Line Road is closed, the level-of-service (LOS) at the intersection of Grandview Road and Vista Drive would change from C to D. LOS D is acceptable to Whatcom County, and therefore traffic flow through the intersection is considered adequate. For further explanation, refer to Enger, Prefiled Testimony, Exhibit 34R.0.

   Construction traffic will not use Brown Road during construction of the cogeneration facility. With little or no increase in traffic on Brown Road, no impact mitigation is proposed.

2. See specific responses below.

2(1) As stated in Malushte, Prefiled Testimony, Exhibit 32R.0, "identification and acknowledgement of a new fault must meet the rigorous 'standard of care' followed in the USGS process. Review of USGS' most recently published PSHA studies (Reference: USGS Open-File Report 02-467; also, visit http://geohazards.cr.usgs.gov/eq/2002faults/flt-spreadsheet-2002.html for the list of recognized faults and their parameters) shows that Sumas and Vedder Mt. faults have not been recognized by USGS. This is despite the fact that the USGS has been conducting focused research in the Pacific Northwest region; yet, the USGS' current research plans (http://geology.wr.usgs.gov/wgmt/pp02.html and http://www.usgs.gov/contracts/nehrp/attach-a.doc) do not include the hypothetical Sumas and Vedder Mt. faults as potential faults that warrant studies."

2(2) As stated in Malushte, Prefiled Testimony, Exhibit 32R.0, "detailed site-specific geotechnical analyses have already been performed for the Cogeneration site. Other soil information from somewhere in the 'area' will not supersede the data developed in these specific geotechnical investigations because geotechnical properties can vary significantly within a distance of mere few hundred feet, let alone miles. If there is any belief that such data may have some significance in terms of regional seismic activity. I would reiterate that the USGS is the most recognized and accepted source for seismic sources (i.e., faults) and hazards. It is unlikely that information for the petroleum exploration studies will provide any relevant and reliable data to improve the design safety of the BP Cogeneration facility."

2(3) The commenter is correct. The findings of the BP Cherry Point Cogen Project, Report of Subsurface Investigation/Laboratory Testing, URS Corporation, July 3, 2003, will assist in the detailed design of foundations and structures.

2(4) As stated in Malushte, Prefiled Testimony, Exhibit 32R.0, "the USGS has already performed a detailed PSHA. The most recent PSHA for the USGS was just published a few weeks ago, October 29, 2003. It shows that the BP Cogeneration facility site has significantly less seismic hazard potential than the default design ground motion prescribed in UBC-97.…Design per UBC-97 will be completely appropriate and will provide a conservative design for the cogeneration facility."

2(5) As stated in Malushte, Prefiled Testimony, Exhibit 32R.0, "the two sites are approximately 23 miles apart. Soil and seismic hazard conditions can vary significantly over such distances….The likelihood of commonalties of any significance between geology of these sites is thus minimal. Reference to analyses related to an entirely separate and distant site, like Sumas Energy 2 location, would provide no useful information for the Cogeneration plant and is more likely to confuse than clarify understanding of conditions at the BP Cogeneration site."

2(6) The report referenced (URS 2003c) is strictly the raw data from geotechnical field investigations to be used by Bechtel Power Corporation during final design of the project components. In his prefiled testimony, Dr. Sanjeev R. Malushte notes that these data were used in a subsurface investigation and foundation report. He also notes that the site has significantly less seismic hazard potential than the default design in the Uniform Building Code. Finally, he noted that a site-specific PSHA would not be appropriate.

2(7) As stated in Moore, Prefiled Testimony, Exhibit 20.0, "what the Applicant said it is willing to do is conduct a periodic monitoring program similar to the one currently in use at the refinery would be appropriate. Under such a program, various aspects of the facility's structural integrity are checked on a regular basis, and after significant seismic events. Inspections include:

- Inspect major foundation seams for differential movement,
- Inspect major foundation grout pads for cracking,
- Check for proper alignment of major piping shoe supports,
- Check piping spring hangers for proper position,
- Check for piping and cable tray misalignment at building penetrations,
- Review equipment vibration monitoring logs for unusual vibration patterns.

"If problems or discrepancies are identified during the inspections, appropriate repairs will be made. These inspections ensure that structural components would continue to serve their intend function.

"The facility will also have vibration monitors on major pieces of rotating equipment. Were a significant seismic event to occur, the cogeneration facility would likely shut down because vibration monitors would see the tremors as high vibrations and would trip the equipment."

3. Thank you for your comment. See Responses 3(1) through 3(44) that address comments provided by Dr. Stenberg in the attached report.

4. See specific responses below.

4(1) Both noise studies used accepted and approved methods for assessing noise impacts. Noise impacts at 15 receptors, both industrial and residential, within an approximate 1.5-mile radius of the cogeneration facility were monitored during the day and night. Modeling was based on existing noise in the area and anticipated noise from the facility. Perceptible noise increases (3 dBA or greater) were not identified at a single site, including immediately adjacent to the proposed facility. Anne Eissinger reports that the herons in the nearby colony showed no evidence of disturbance either by the existing refinery or the recent construction of a bridge over Terrell Creek within 1,000 feet of the colony.

4(2) Roadside measurements were taken to assess the impact of predicted changes in vehicular traffic patterns, primarily during the construction phase of the project, but also to a lesser extent operational truck noise. The 15-minute time frame is typical of traffic noise measurements taken in accordance with FHWA/WSDOT noise measurement protocols (FHWA 1996, WSDOT 2003).

The time of day these measurements were taken is not important because the purpose of the measurement is to calibrate the traffic noise model by comparing actual noise measurements to modeled results.

The roadside measurements were not intended to provide background noise information. Suitable background levels are available from the Hessler study, the results of which are presented in Table 3.9-5 of the Draft EIS.

4(3) Washington State and most other state and federal agencies that deal with noise issues require the use of A-weighted noise level measurement to assess environmental noise impacts. A-weighting estimates the response of the human ear under conditions that would reasonably be judged normal. C-weighting is most often used for extremely highnoise levels and short-term noise sources, such as pile-driving, but not for industrial facilities similar to the cogeneration facility being considered by the EIS. At Fort Lewis, Washington, the U.S. Army uses C-weighting in artillery-related noise control.

4(4) Washington State environmental noise regulations (WAC 173-60) were observed for this study. The WAC rules apply throughout the state and are considered reasonable and appropriate for this EIS.

The suggested approach would be a “relative” approach to noise limitation, as used by most Departments of Transportation in defining noise levels for new construction that would “substantially exceed” existing levels. Such levels are typically in the 10 to 15 dB range. The WAC 173-60-040 uses an “absolute” approach in defining impacts that is invoked for all projects throughout the state. In any case, as noted in Table 3-9.4 of the

Draft EIS, 3 dB is greater than the noise impact modeled at any receptor. Most noise-related literature regards 3 dB to be at the threshold of perceptible change. The perception of a noise increase is not automatically considered a noise impact.

4(5) Greater sensitivity to nighttime environmental noise is compensated by the noise limitations in WAC 173-60-040, which reduce allowable nighttime noise by 10 dB for all categories of noise receptors, including residential. Eliminating the daytime sound levels from the average would artificially weight the data to a degree not intended by the regulation.

4(6) Sound propagates spherically from a point (stationary) source, dispersing geometrically at a minimum rate of roughly 6 dB for each doubling of distance from the source (without taking into account ground absorption or meteorological interference, which is not consistent throughout the seasons or from one year to the next). A sound measured at 80 dB (very noisy) at a distance of 15 meters would therefore attenuate by more than 36 dB at 1,440 meters to 44 dB, below even nighttime noise limits per the WAC. Noise impacts were modeled for sites much closer to the proposed cogeneration facility than 1,400 meters (see Figure3.9-1 of the Draft EIS), and no perceptible noise impacts were identified (Table 3.9-4 of the Draft EIS).

4(7) A change of 1 dB can be perceived under specific conditions, but most authorities consider that under non-laboratory conditions in a heterogeneous noise environment typical of most residential situations where midrange frequency sounds are dominant 3 to 5 dB is the minimum perceptible change in noise level for people with average hearing ability.

4(8) Please refer to Response 4(3) of this letter. Table 3.9-5 of the Draft EIS shows that low frequency noise would be well below the American National Standards Institute (ANSI) recommended limit of 75 to 80 dBC at all but one location—an industrial site. Evaluation of low frequency noise in the Draft EIS exceeds the requirements of applicable regulation and indicates a level of diligence above the norm.

4(9) Eissinger (Prefiled Testimony, Exhibit 31R.0) notes that there is no apparent impact from existing noise at the refinery on the nearby heron colony and that it is reasonable to use standards for noise impacts on human beings to assess impacts on wildlife.

4(10) Please refer to Response 3(2) of this letter. Also, Ann Eissinger testified that the herons “exhibited no observable response” to a bridge construction site (within 1,000 feet of the colony) or the concurrent construction activity at the refinery. Based on these observations, further analysis is not warranted.

5. The project, as proposed, includes only a compressor station constructed within the fenceline of the refinery. The Applicant separately evaluated the feasibility of constructing a compressor at or near Sumas but determined it would not be economically practical and therefore is not part of the proposed project.

6. Please refer to Response 5 of this letter.

7. The project includes "end-of-line" compression inside the refinery fenceline. This compressor would also be within the Heavy Impact Industrial zone of Whatcom County. Please refer to Response 5 of this letter.

8. Thank you for your comment.

<u>Attached Report</u>

3(1) Thank you for your comment. USFWS does not identify great blue heron as a species of concern, candidate, or proposed species for listing. Whatcom County, however, identifies it as a species of local concern. The term "critical habitat" is applied in reference to Endangered Species Act–related species. Critical habitat has not been scientifically defined for great blue heron. Quality habitat associated with great blue heron staging and foraging activities, such as Drayton Harbor, Birch Bay, and Lummi Bay, is located within a 4-mile radius of the Birch Bay great blue heron colony. As described in Section 3.7.1 of the Draft EIS, however, the dominant presence of non-native, invasive plant species associated with the project site (reed canarygrass), including wetland mitigation sites, do not provide habitat conditions typically identified as quality habitat for great blue heron. Reed canarygrass is not generally considered to be a quality foraging habitat for great blue herons because of its height during the growing season and thick matted nature when down in the winter. In addition, long term monitoring of the Birch Bay great blue heron colony has not documented great blue heron staging or foraging activity at the project site or project wetland mitigation areas. Great blue heron habitat and potential project-related impacts on great blue heron are thoroughly addressed in Eissinger, Prefiled Testimony, Exhibit 31R.0.

Mitigation sites located west of the project wetland mitigation sites, as described in the Brown Road Materials Storage Area Final Mitigation Plan (URS 2003a) and Habitat Management Plan (URS 2003b), do not provide habitat conditions typically identified as quality foraging and staging habitat for great blue heron.

As described in Section 3.7.2 of the Draft EIS, treated wastewater associated with the BP refinery's National Pollutant Discharge Elimination System (NPDES) permitted outfall is not likely to significantly affect Puget Sound habitat that supports a variety of aquatic species such as salmon, other fish, shellfish, and other marine wildlife. Great blue heron foraging habitat associated with the marine environment of Drayton Harbor, Birch Bay, and Lummi Bay is located more than 2.5 miles from the project outfall. Michael Kyte, in Prefiled Testimony Exhibits 27.0 and 27R.0, addresses impacts on marine water quality issues, including toxin bioaccumulation and/or heavy metals.

3(2) Potential impacts on wildlife associated with noise are discussed in Section 3.7.2 of the Draft EIS. As discussed in Section 3.9, Noise, the project meets state standards for noise, and modeling shows that noise associated with the project would result in a 1 dBA increase over existing background noise at most receptor locations. It should also be noted the refinery has been in operation for over 30 years and the herons have continued to occupy the rookery. Whatcom County has approved two residential developments within 1 mile of the Birch Bay great blue heron rookery: a 66-lot residential development located less than a mile northeast of the rookery and a 125-lot residential development located about a half mile northeast of the rookery. Ann M. Eissinger, in Prefiled Testimony Exhibit 31R.0, addresses potential noise impacts on great blue heron.

Under Section 3.7.2 Impacts of the Proposed Action, Construction, Wildlife and Habitat, the following text will be added to the Final EIS: "The Birch Bay great blue heron rookery is located about 1.5 miles from the project site. WDFW management recommendations (2004a) for great blue heron include a 3,280-foot buffer between heron colonies and construction activities." A cooperative agreement between the Applicant and Whatcom County has been completed that addresses noise impacts associated with wildlife.

3(3) Please refer to Response 3(2) of this letter. In addition, as discussed in Eissinger, Prefiled Testimony, Exhibit 31R.0, scientific literature lacks sound-tolerance levels or guidelines to accurately asses impacts on wildlife from noise. Reliance on human levels of tolerance and perceptibility is generally accepted as the best available measure. Potential levels of noise reaching the heron colony and areas of primary use are so low that impact on the herons is unlikely.

3(4) Please refer to Responses 3(2) and 3(3) of this letter. As discussed in Section 3.9, Noise, noise associated with the proposed project would not result in a perceptible increase over ambient background noise. Because maximum noise levels were evaluated, any variation in noise from the project would be a decrease and would not be audibly perceptible.

3(5) Please refer to Responses 3(2), 3(3), and 3(4) of this letter.

3(6) Please refer to Responses 3(2), 3(3), and 3(4) of this letter.

3(7) Please refer to Responses 3(2), 3(3), and 3(4) of this letter.

3(8) As noted in Response 3(2) of this letter, the heron colony is about 1.5 miles from the proposed cogeneration facility. Two of the three noise receptors in the vicinity (south and east of the colony) showed no increase in modeled noise, whereas a third (to the west) showed measurable but not perceptible noise increases. Please refer also to Responses 3(3) and 3(4) of this letter.

3(9) Please refer to Response 3(1) of this letter.

3(10) Construction noise impacts on wildlife are addressed in Section 3.9.2 of the Draft EIS, where it is acknowledged some wildlife may be disturbed during the two-year construction period. In addition, please refer to Responses 3(2), 3(3), and 3(4) of this letter.

3(11) The Draft EIS notes an imperceptible change in noise (0 to 1 dBA at all but one of 15 receptors) relative to existing conditions. In addition, please refer to Responses 3(1), 3(2), 3(3), and 3(4) of this letter.

3(12) Outdoor lighting would generally provide operator access and safety. Lighting off the ground on outdoor equipment would only be required at monitoring platforms. As noted in Section 3.7 of the Draft EIS, exhaust stacks would not be lighted. Because of its location adjacent to the much larger refinery, the cogeneration facility's incremental increase in lighting is expected to be insignificant.

3(13) The commenter is correct that navigation lights will not be necessary on the cogeneration exhaust stacks. Lighting that would be included in the design of the cogeneration facility would enhance safe working conditions. In addition, structures would be painted gray to decrease glare from lights at night and sunlight during the day. Proposed landscaping with trees to the east and north of the cogeneration facility would further reduce the effect of light and glare.

3(14) Please refer to Response 3(13) of this letter.

3(15) Please refer to Letter 23, Response 7, and Response 9 of this letter. Kyte (Prefiled Testimony, Exhibits 27.0 and 27R.0) in his prefiled testimony states, "the Refinery has had no measurable adverse impact on marine water quality during its 30-year history. It is unlikely that the addition of wastewater from the Cogeneration plant, including trace metals, will have an adverse effect during its 30-year projected life." Kyte further states that he has seen no evidence for, "any negative impact to fish or their food sources from the Refinery outfall. The addition of the wastewater effluent from the Cogeneration project should have no additional impact."

3(16) Table 3.4-5 of the Draft EIS shows that refinery wastewater after addition of the cogeneration facility water would be 82.7°F. As presented in the Fact Sheet for the State Waste Discharge Permit, a temperature analysis was conducted of the combined (refinery and cogeneration facility) discharge. The results of the analysis indicated the temperature loading from the cogeneration facility was negligible and in fact the cogeneration wastewater would probably be lower than the refinery process wastewater and the combined discharge would be within water quality standards. The State Water Quality Standards are designed to protect biota in the receiving waters around the refinery outfall.

3(17) Please refer to Letter 23, Response 7.

3(18) Thank you for your comment.

3(19) Please refer to Response 3(15) of this letter.

3(20) Please refer to Response 3(15) of this letter.

3(21) Please refer to Responses 3(15) and 3(16) of this letter.

3(22) Please refer to Letter 17, Response 23. The stormwater collection and treatment system for the cogeneration facility is described in detail in Section 3.4.2 of the Draft EIS. Stormwater would be treated at the cogeneration facility site prior to being discharged to the wetland areas north of Grandview Road. All stormwater discharged to the wetland mitigation areas is expected to meet water quality standards.

3(23) Section 2.2.2 of the Draft EIS states that the stormwater facilities would be designed consistent with Whatcom County and Department of Ecology requirements, including the Stormwater Management Manual for Western Washington (Ecology 2000).

3(24) Section 2.2.2 of the Draft EIS states the cogeneration facility would occupy approximately 33 acres. This would be mostly impervious surface and would be subject to stormwater design constraints. Please refer to Response 3(23) of this letter.

3(25) Thank you for your comment. As stated in David Every's prefiled testimony, Exhibit 28R.0, "it is true that bullfrogs are known to find and reproduce in stormwater ponds. However, that can be prevented by making sure that the ponds go dry during the dry summer or fall months. Salamanders and other amphibians in the area have shorter life cycles and can complete metamorphosis to the land stage in a few months. If the ponds are designed to allow both entry and exit by the amphibians, then they need not become mortality sinks. However, only species that find the other conditions suitable for reproduction are likely to be present. Some species require certain structural features, such as redds, to deposit their eggs. If those features are not present, the species will not breed there. The ponds will be designed and managed to avoid the problems noted."

3(26) The Draft EIS notes the net benefit is a result of 110 acres of habitat creation and restoration that would occur as compensation for the loss of 30.5 acres of generally low quality wetland habitat.

3(27) Thank you for your comment. Grading will be minimized purposely to limit impacts resulting from earth disturbances. Permanent ponds will be avoided to prevent creating bullfrog habitat.

3(28) The revised mitigation plan addresses herons. According to David Every (pers. comm., 2004), no permanent pond was created. The ponds that were created go dry by late summer and do not support bullfrog reproduction. The cogeneration project mitigation will be governed by a 10-year monitoring requirement with the initial as-built report and each annual report delivered to the Corps of Engineers, the Department of Ecology, and Whatcom County for review.

3(29) According to David Every (pers. comm., 2004), the pond created for waterfowl habitat was unfortunately created with steep slopes on the islands. The banks did not erode to their current configuration but have been stable. While water level fluctuation does occur, it does not cause erosion in the ponds, and the level of the ponds does not fluctuate excessively. The driving principle for the hydrologic restoration for this project was to plug ditches and spread water out over broad areas. Water will be directed to CMA2 to get it back to historical pathways that have been disrupted by roads and ditches, but that water will also be spread widely. Detailed hydrologic monitoring is being required as part of mitigation, and it will allow and guide adaptive management as necessary.

3(30) Monitoring heron use of the habitat is being conducted for a year. The results will provide data on both areas and patterns of usage as well as timing. The information will be used to establish the timing of mitigation actions as needed to be sensitive to established heron needs. Please refer also to Response 3(1) of this letter.

3(31) The results of the monitoring mentioned above will be used to adjust activities to the appropriate season. Any tilling will be started early enough to displace nesting activities of ground-nesting birds rather than disrupt established nests.

3(32) The mitigation plan will establish additional forest that could become attractive to herons in the future. The mitigation plan specifically states what measures are included to make remaining habitats more attractive to herons. Please refer also to Response 3(1) of this letter.

3(33) The intent is to use materials available at the site as much as possible. The initial benefit of the habitat features is likely to be most important. As the plantings develop, structural diversity of habitat will improve. In addition, even decomposing woody debris provides some additional habitat value (Every, pers. comm., 2004).

3(34) As noted in the mitigation plan, the artificial snags with cross beams are intended for perching; herons perch on higher vegetation but hunt from the ground. Again, the intent is to provide habitat structure in the short term before the planted trees grow large enough to provide the structure (Every, pers. comm., 2004).

3(35) The intent is to use rooted vegetation, such as rushes, sedges, and grasses, to provide amphibian egg deposition sites. Some experiments in King County, Washington, demonstrated that the function could be provided by artificial structure, but that is not what is proposed here (Every, pers. comm., 2004).

3(36) The brush shelters are proposed for open areas where additional vole production would help herons, not for areas where woody plantings might be affected by voles.

3(37) Thermal benefits, while likely, are probably of minor consequence in coastal Whatcom County where there are few mountains to influence temperature or limit dispersal of wildlife (Every, pers. comm., 2004).

3(38) Benefits come from structural diversity increases, forested connections to the Terrell Creek corridor, and reduction of invasive species, in addition to increases in plant diversity. The proximity of the restoration and compensatory mitigation areas to the active refinery places them in a noise and light impact situation similar to what will result after the cogeneration facility is built; the incremental impact on wildlife use will be small. The functions of the impact areas as wildlife habitat are already degraded because of past activity, including agricultural activity and the building of roads and ditches. The temporal loss will therefore be small and will be compensated by the mitigation measures (Every, pers. comm., 2004).

3(39) Thank you for your comment. Species lists are not a good indicator of impacts. Discussion of effects on habitat is much more important (Every, pers. comm., 2004).

3(40) Thank you for your comment. As described in Section 3.7.1 of the Draft EIS and in Response 3(1) of this letter, the project site and wetland mitigation sites do not provide habitat conditions typically identified as quality foraging or staging habitat for great blue heron. In addition, monitoring of the Birch Bay great blue heron colony has not documented great blue heron staging or foraging activity at the project site or wetland mitigation areas (Eissinger, Prefiled Testimony, Exhibit 31R.0).

3(41) Species of local importance are now addressed in the mitigation plan. Increasing the shrub and forest cover in the Compensatory Mitigation Areas (CMAs) will benefit neotropical migrants in general by providing more suitable habitat. According to the Washington Department of Fish and Wildlife (WDFW) Priority Habitat and Species database, four eagles' nests are located within 2 to 4 miles of the proposed project. Loons have been reported at Lake Terrell about 2 miles away. Pileated woodpeckers could be found along Terrell Creek. Although they could fly over the project site, none of these species or others on Whatcom County's list of species of local significance is likely to use habitats present on the site.

3(42) According to WDFW (2004b), coho salmon, cutthroat trout, and largemouth bass have been documented in Terrell Creek, as noted in Section 3.7.1 of the Draft EIS. WDFW, however, have not documented Puget Sound chinook salmon use of Terrell Creek. NOAA Fisheries and the USFWS have issued their concurrence that the project is not likely to adversely affect any threatened or endangered wildlife or fish species. Concurrence letters from NOAA Fisheries and the USFWS have been added to the Final EIS in Appendix B of this Final EIS.

3(43) As discussed in Response 3(1) of this letter and by Eissinger, Prefiled Testimony, Exhibit 31R.0, the project site and wetland mitigation sites do not provide habitat conditions typically identified as quality foraging or staging habitat for great blue heron. Mitigation sites located west of the project wetland mitigation sites, as described in the Brown Road Materials Storage Area Final Mitigation Plan (URS 2003a) and Habitat Management Plan (URS 2003b), do not provide habitat conditions typically identified as quality habitat for native wildlife species (great blue heron). Proposed wetland mitigation designs for these projects, including planting native tree and shrub vegetation, would improve overall habitat conditions for native wildlife species.

BP has agreed to fund the development of a comprehensive management plan for its land holdings north of Grandview Road. The plan, which will be developed by Western Washington University, will guide and coordinate future actions in the area.

3(44) Thank you for your comment. Please refer to the biological evaluation and the wetland mitigation plan. The mitigation plan and its supporting documents describe how the mitigation sequence has been followed (Every, pers. comm., 2004).

Response to Comment in Letter 26 from Steve and Helene Irving, Ferndale Residents

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. The project would meet all state and federal standards for air quality. In addition, there would be a reduction in air emissions due to shutting down older utility boilers. The water reuse project being developed jointly with Alcoa Intalco Works, Whatcom PUD, and the Applicant, on average, would provide more "reuse" water than the cogeneration facility would use thereby reducing the amount of water normally withdrawn from the Nooksack River.

   Regarding constructing a smaller facility and/or purchasing power from Sumas Energy 1 and Sumas Energy 2 generation facilities, please refer to General Response A.

Response to Comment in Letter 27 from Judith Leckrone Lee, Manager, Geographic Implementation Unit, US EPA

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. The revised Alternatives Analysis (see Appendix A in the Final EIS) provides more detail on the siting of the proposed cogeneration facility to limit wetland impacts.

2. The proposed wetland mitigation plan has been developed in consultation with the Corps of Engineers, Washington Department of Ecology, Washington Department of Fish and Wildlife, and Whatcom County. Wetland functions for both the project site and the wetland mitigation areas were rated using the Methods for Assessing Wetland Functions (Ecology 1999), which is based on the Hydrogeomorphic Approach for Assessing Wetland Functions. Based on this functional assessment, the wetland mitigation area provides an increase in functions and values to fully mitigate wetland impacts of the proposed project.

3. Please refer to Response 2 of this letter.

4. Bonneville has asked officials with the Lummi Tribe whether they have any remaining concerns about the project; they expressed no need for further consultation with Bonneville.

Responses to Comments in Letter 28 from Cathy Cleveland, Blaine Resident

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Existing water quality and potential impacts are discussed in Section 3.4 Water Quality rather than Section 3.3 Water Resources of the Draft and Final EISs. Table 3.4-5 of the Draft EIS indicates that the existing flow of wastewater to the Strait of Georgia is 2,338 gallons per minute (gpm) and that the cogeneration facility would add an additional 190 gpm. Assuming the facility operates 24 hours a day, the daily discharge added to what is currently being discharged by the refinery would be 273,600 gallons. As discussed in Letter 25, Response 3(15), there would be no discernable difference between the quality of the discharge water and that of the background water quality when measured at the boundary of the permitted mixing zone. This would include salinity and temperature, as well as other characteristics.

2. Thank you for your comment. The decline in the herring population off Cherry Point has been added to the Final EIS. Kyte (Prefiled Testimony, Exhibits 27 and 27R.0) notes no evidence of adverse effect on the fish populations off Cherry Point from the existing wastewater discharge. He also anticipates no adverse effect from the additional discharge from the cogeneration facility. Please refer also to Letter 25, Response 3(15).

3. Thank you for your comment. The great blue heron rookery located about a mile from the project site is discussed in Section 3.7.1, Existing Conditions, State Priority Species, of the Draft EIS.

   As described in Section 3.7.2, Impacts of the Proposed Action, in the Draft EIS, treated wastewater associated with the National Pollutant Discharge Elimination System (NPDES) permitted outfall is not likely to significantly affect Puget Sound habitat that supports a variety of aquatic species such as salmon, other fish, shellfish, and other marine wildlife. NOAA Fisheries and the USFWS have issued their concurrence that the project is not likely to adversely affect any threatened or endangered wildlife or fish species. Concurrence letters from NOAA Fisheries and the USFWS have been added to the Final EIS in Appendix D of this Final EIS.

4. Please refer to Response 2 of this letter.

5. Thank you for your comment. Washington Department of Natural Resources (DNR) is developing a master plan for the Cherry Point Aquatic Reserve; when it is completed, DNR will prepare an EIS.

6. Thank you for your comment.

7. The project has been designed to minimize the emissions of particulate, both as criteria pollutants and as toxic air pollutants. The U.S. Environmental Protection Agency has identified five types of atmospheric pollutants that can contribute to marine deposition:

nitrogen compounds, mercury, other metals, pesticides, and emissions (excluding nitrogen compounds) associated with the incineration of wastes. Emissions of nitrogen compounds will be minimized through the use of Best Available Control Technology (BACT) for both nitrogen oxides (NO_x) and ammonia emissions. The deposition of mercury and other metals from combustion processes are associated with the combustion of dirtier fuels such as coal and fuel oil. The natural gas fuel used for the project is very clean and will not contribute significant amounts of mercury or other metals to the airshed. The project air emissions will not be a source of any types of pesticide. Finally, the project will not combust wastes and will not be a significant source of polycyclic aromatic hydrocarbons (PAHs) or other persistent biocumulative toxins. Because of the clean type of fuel being used by the project and the additional emission controls, the project is not expected to contribute pollutants to local marine waters.

8. Please refer to Response 7 of this letter.

9. Please refer to Response 7 of this letter.

10. Please refer to all responses to Letter 12 for concerns raised by Mr. Cleveland.

11. Thank you for your comment. Section 3.2 of the Final EIS includes a discussion on the health impacts of $PM_{2.5}$.

12. Through the Prevention of Significant Deterioration (PSD) program, emission controls proposed by the Applicant undergo strict scrutiny. Only BACT technology is ultimately permitted. BACT technology must meet three important criteria: technical and commercial feasibility, cost efficiency per ton of pollutant removed, and most efficient removal rate of the pollutant of concern. The commenter suggests the use of the following emission control technologies: gravitational settling, centrifugal separators, wet scrubbers, baghouse filters, and electrostatic precipitators (ESPs). The large volume and dilute nature of the emissions from the combustion turbines render all of these techniques inappropriate for cost and pollutant removal efficiency reasons. Gravitational settling and centrifugal separators are only applicable to large particulate matter such as fly ash, which would not be generated by a combustion turbine facility burning natural gas. These technologies would not be appropriate for high volumes of exhaust that contain a low concentration of particulate, such as the emission from the project. Wet scrubbers, baghouse filters, and ESPs are not cost efficient for the treatment of large volume and dilute emissions of fine particulate. The nature of the particulate also does not lend itself to ESP control. For ESPs, which operate on the principle of charge migration, the low particulate concentration would prevent significant charge buildup on particles, resulting in low migration of particles to the collecting plates. For these turbines, the peak particulate emission concentration is 0.001 to 0.003 grains per standard cubic foot (gr/scf) during natural gas firing, which approaches concentrations that ESP and baghouse vendors are striving to achieve for particulate control in other applications (such as oil-fired or other fossil-fuel fired boilers). The use of an ESP and/or baghouse filter is considered technically infeasible and not representative of BACT. The most stringent “front-end” particulate control method demonstrated for combustion turbines is the use of

low-ash fuel and/or low-sulfur fuel such as natural gas and controlled combustion to minimize particulate formation.

13. Thank you for your comment. The referenced sentence in Section 3.10.1 (Existing Land Use, Project Site and Surrounding Area) of the Draft EIS has been revised as follows: “Northwest of the refinery, residential properties occur in the bayfront community of Birch Bay. According to U.S. Census data in 2000, the Birch Bay Census Designated Place supported a total of 5,105 total housing units with a corresponding population of 4,961. Of the total number of housing units, approximately one-half or 2,620 units were classified as seasonal or occasional use units (Whatcom County 2003a).”

14. Through state law, the Legislature mandates that EFSEC review the impacts of large energy facilities under its jurisdiction, such as this project. State law also requires that EFSEC be the lead agency under the State Environmental Policy Act (SEPA). EFSEC prepares the Environmental Impact Statement pursuant to SEPA law and regulations, which apply equally to all state and local governments in Washington State. EFSEC law also requires that a third party independent consultant be retained to prepare the EIS. Finally, EFSEC contracts with other state agencies to review other permits that may be required by state law or regulation. In formulating its recommendation to the governor, EFSEC must balance the increasing demands for energy facility location and operation in conjunction with the broad interests of the public, which include public health and welfare, and protection of the environment. The governor will make the final decision.

    The Bonneville Power Administration proposes to interconnect the project with the federal transmission system and is the lead federal agency for purposes of the National Environmental Policy Act of 1969 (NEPA). Bonneville’s administrator is officially responsible for the EIS as specifically required by NEPA and implementing regulations.

15. Thank you for your comments regarding the odor emissions from the refinery reported by local property owners. The cogeneration project will not be powered by crude or refined petroleum products. Clean natural gas will be burned in the combustion turbines. Sulfur concentrations in the natural gas fuel are extremely low compared with concentrations in oil received from Alaska. Furthermore, combustion of natural gas in the turbines does not emit odors comparable to oil refining processes at the existing refinery. The cogeneration project would therefore not contribute to existing odor problems experienced by local residents.

16. Please refer to Response 15 of this letter.

17. The commenter is correct that the U.S. EPA has established ambient air quality standards for $PM_{2.5}$. However, thresholds to measure impacts of $PM_{2.5}$ under the PSD program have not been established yet. Furthermore, Washington State and the U.S EPA have only recently begun to designate attainment, nonattainment, and unclassifiable areas for $PM_{2.5}$. Table 3.2-11 of the Final EIS indicates ambient concentrations of $PM_{2.5}$ resulting from the project, when added to background levels, do not violate the standards adopted by EPA. Please refer to Letter 12, Response 2 for an analysis of $PM_{2.5}$ emissions compliance

under PSD. Finally, as stated in both the Draft and Final EISs, $PM_{2.5}$ emissions were conservatively estimated as equal to PM_{10} emissions.

18. The cogeneration facility is considered a major source and is therefore required to undergo PSD review because emissions of one or more criteria pollutants exceed 100 tons per year (tpy). The annual emissions from the cogeneration project are shown in Table 3.2-7 of the Final EIS. The 100 tpy threshold for PSD review was exceeded for the following pollutants: NO_x by 133.3 tpy; CO by 57.7 tpy; PM_{10} and $PM_{2.5}$ by 161.6 tpy. It should be noted, however, that to require further analysis under the PSD program, source emissions must only exceed the 100 tpy thresholds, no matter by how much.

    The statement regarding the regulation of $PM_{2.5}$ under the PSD program has been corrected in the Final EIS. It has been determined that $PM_{2.5}$ emissions do not violate state or national ambient air quality standards.

    The mitigation measures proposed by the Applicant (i.e., the emissions control technologies) have been selected based on their compliance with Best Available Control Technology, as mandated by the PSD program. The selected control technologies all represent the highest level of emissions control commercially available for the pollutants in question. These technologies are: selective catalytic reduction for NO_x, an oxidation catalyst for volatile organic compounds and carbon monoxide, and the use of clean natural gas fuel and best combustion practices for particulate matter and sulfur oxide emissions. Regulatory compliance for air emission will be established through a Prevention of Significant Deterioration/Notice of Construction (PSD/NOC) permit that would be issued if the governor approves the project. Permit noncompliance for any and all regulated pollutants would be addressed through appropriate enforcement mechanisms and financial penalties as required by state and federal law and regulations.

19. The Applicant has demonstrated that all regulated air pollutant emissions including both criteria and toxic pollutants from the cogeneration facility will not violate ambient air quality standards. Ambient air quality standards have been established to conservatively protect the health of the population. State and federal regulations do not require baseline monitoring of people’s health if a project has demonstrated compliance with applicable standards and thresholds.

20. Both the state and national ambient air quality standards (for criteria pollutants) and the Acceptable Source Impact Levels (ASILs) (for toxic pollutants regulated under state law) conservatively protect human health. The ASILs do not represent a threat to human health, but a level of concern that requires additional modeling to assess whether a threat to human health could exist. Emissions that do not exceed the ASILs are considered below the level of regulatory concern and do not require additional analyses, including the evaluation of synergistic effects. The clean natural gas fuel that will be used by this project would further limit the emissions of toxic pollutants.

21. Please refer to Response 20 of this letter.

22. Please refer to Response 20 of this letter.

23. The proposed project must be located adjacent to the steam host, the BP Cherry Point Refinery. The proposed project would deliver about 510,000 lbs/hr, 750°F, 600 psig steam to the refinery. This steam line must necessarily be as short as possible to minimize heat loss. For a discussion regarding alternative siting of the proposed project and project size, please refer to General Response A.

Responses to Comments in Letter 29 from Kathy Berg, Birch Bay Resident

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. The Applicant has performed extensive modeling of the impacts of air emissions from the proposed project. The modeling was performed to satisfy the requirements of the Federal Prevention of Significant Deterioration (PSD) program and the State of Washington's new source review program. In addition, federal land managers (Forest Service and National Park Service) were consulted regarding impacts on Class I areas that are federally protected. All of the modeling was reviewed for EFSEC by the Department of Ecology and had to meet strict regulatory requirements and guidelines. Emissions of all regulated pollutants, including particulate matter, have been shown to be well below any applicable protective thresholds, and they do not violate national or state ambient air quality standards. Ambient air quality standards conservatively protect the environment and human health.

   As indicated in Section 3.2 of the Final EIS, the Applicant went beyond federal requirements to also analyze the impacts of the emissions in Canada, including impacts on the Fraser Valley. If considered alone, the particulate emissions from the project are well within any Canadian regulatory standards and objectives. In addition, the Applicant has committed to remove three existing boilers at the BP Cherry Point Refinery should the cogeneration project proceed to construction. Removal of these boilers will decrease the overall impact of the project's particulate emissions in both Whatcom County and Canada.

   If approved by the governor, the project would be subject to the conditions of a Prevention of Significant Deterioration/Notice of Construction (PSD/NOC) air emissions permit, which would require monitoring of all emissions and reporting of results to EFSEC and Environmental Protection Agency. If permit conditions are exceeded and it is deemed that an immediate risk to public health may be involved, EFSEC has the authority to stop project operations until the problems are resolved.

2. The project would meet the state and county noise standards. In addition, noise modeling shows that the cogeneration facility is not likely to be heard above existing background (refinery) noise. Three background noise surveys have been conducted around the project site, including the Birch Bay area and Birch Bay Village. One of these surveys was conducted along with a representative of the Whatcom County Planning and Development Services, Jim Thompson. The engineering and construction contractor has guaranteed the Applicant that noise levels would be consistent with the Application for Site Certification. Pre- and post-construction monitoring would be conducted as part of performance testing.

Responses to Comments in Letter 30 from Tom Pratum, Bellingham Resident

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. A shutdown of the Alcoa Intalco Works would have no practical effect on PUD water diversions from the Nooksack River. If operations at the Intalco facility were suspended or shut down, water would be transmitted directly to the cogeneration facility instead of being transmitted through the Alcoa Intalco Works cooling system. In fact, because the average amount of water required for the cogeneration facility is less than the approximately 4 million gallons per day historically used by Intalco and the extra, reused water would be used by the refinery, the amount of water taken from Nooksack River would be reduced (Anderson, Prefiled Testimony, Exhibit 25.0).

2. Potential temperature increases are addressed in Letter 25, Response 3(16). The final, combined effluent from the refinery and cogeneration facility will be well below permitted limitations as discussed in Letter 23, Response 7.

3. Please refer to Letter 25, Response 3(2).

Responses to Comments in Letter 31 from Doralee Booth, Birch Bay Resident

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1 The commenter is correct that removal of the refinery boilers will not reduce all emissions generated by the cogeneration project. As indicated in Table 3.2-20 of the Final EIS, however, removal of the refinery boilers will reduce emissions for each criteria pollutant from the refinery. Section 3.2 of the Draft EIS has been updated and revised to explain more clearly how emissions for each criteria pollutant will increase or decrease if removal of the refinery boilers is considered. It should be noted, however, that for purposes of regulatory review and assessment of impacts on ambient air quality standards, refinery reductions were not taken into account.

2. Regarding the explanation of health risks, the standards and thresholds used for regulatory review conservatively protect human health. Criteria pollutant emissions are evaluated for their potential to violate state and ambient air quality standards (see Table 3.2-11 of the Final EIS). The Environmental Protection Agency established ambient air quality standards to protect public health, including the health of "sensitive" populations such as asthmatics, children, and the elderly.

Should the governor approve this project, a Prevention of Significant Deterioration/Notice of Construction (PSD/NOC) permit would be issued to place conditions on air emissions from the project. Air emissions would be monitored on a regular basis and reported to EFSEC. Background monitoring would continue throughout Whatcom County and the Fraser Valley at existing monitor locations managed by the Department of Ecology.

The refinery's Risk Management Plan (RMP) will be updated to include planned activities and responsibilities in case of an accidental catastrophic event or major release of ammonia. Refer to Section 3.16 of the Final EIS for additional information regarding the RPM.

3. Thank for your comment. Every effort has been made to prepare a readable and concise environmental review document for the proposed cogeneration project.

Responses to Comments in Letter 32 from John Williams, Williams Research, Portland, Oregon

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Thank you for your comments. Responses to your comments can be found in Letter 17, Response 1(1).

2. Please refer to Letter 17, Response 1(2).

3. Please refer to Letter 17, Response 1(3).

4. Please refer to Letter 17, Response 1(4).

5. Please refer to Letter 17, Response 1(5)

6. Please refer to Letter 17, Response 1(6).

7. Please refer to Letter 17, Response 1(7).

8. Please refer to Letter 17, Response 1(7).

9. Please refer to Letter 17, Response 1(27).

10. Please refer to Letter 17, Response 1(8).

11. As described in Section 2.4.4 in the Draft EIS, alternative air emission control technologies were evaluated. Both SCONOx and XONON technologies were not selected for technological and economic reasons. The emission control technology that was selected is the selective catalytic reduction or SCR system. Anhydrous ammonia will be used in the SCR system to control of nitrogen oxide (NO_X) emissions. This projected amount of ammonia from the exhaust stacks indicates that the public exposure to ammonia (approximately 5.8 µg/m^3 or 0.008 ppm) will be below the accepted range where an ammonia odor could be detected (5 to 53 ppm). Relative to the public health exposure of ammonia, the maximum projected ground-level impact of the ammonia emissions is about 6% of the 100 µg/m^3 24-hour health-based standard identified in WAC 173-460.

12. Please refer to Letter 17, Response 1(10).

13. Please refer to Letter 17, Response 1(11).

14. Please refer to Letter 17, Response 1(12).

15 Please refer to Letter 17, Response 1(13).

16. Please refer to Letter 17, Response 1(14).

17. Please refer to Letter 17, Response 1(15).

18. Please refer to Letter 17, Response 1(16).

19. Please refer to Letter 17, Response 1(17).

20. Please refer to Letter 17, Response 1(18).

21. Please refer to Letter 17, Response 1(19).

22. Please refer to Letter 17, Response 1(20).

23. Please refer to Letter 17, Response 1(21).

24. Please refer to Letter 17, Response 1(22).

25. Please refer to Letter 17, Response 1(23)

26. Please refer to Letter 17, Response 1(24).

27. Please refer to Letter 17, Response 1(25).

28. Please refer to Letter 17, Response 1(26).

29. Please refer to Letter 17, Response 1(28).

30. Please refer to Letter 17, Response 1(29).

31. Please refer to Letter 17, Response 1(30).

32. Please refer to Letter 17, Response 1(31).

33. Please refer to Letter 17, Response 1(32).

34. Please refer to Letter 17, Response 1(33).

35. Please refer to Letter 17, Response 1(34).

36. Please refer to Letter 17, Response 1(35).

37. Please refer to Letter 17, Response 1(36).

38. Please refer to Letter 17, Response 1(37).

Responses to Comments in Letter 33 from Cathy Cleveland, Birch Bay Resident

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Three noise monitoring surveys have been conducted. The last survey was coordinated with: Sharon Roy, Whatcom County Council; David Grant, assistant prosecuting attorney; and Jim Thompson, Whatcom County Planning and Development. This group chose three locations for additional monitoring. Monitoring results from these locations were used to model potential noise impacts resulting from operation of the proposed project. No additional noise monitoring is necessary.

2. Baseline noise monitoring collected data for 60 consecutive hours over three days and two nights.

3. This EIS evaluates the impact of noise associated with the cogeneration facility relative to ambient noise. Because the cogeneration facility would be quieter than the refinery, if monitoring were done when the refinery is exceptionally noisy the cogeneration facility would have even less of a relative impact.

4. Potential noise impacts resulting from operation of the proposed cogeneration project have been addressed in Section 3.9 of the Final EIS.

5. In Table 3.9-5 of the Draft EIS, the baseline noise levels are identified as "existing conditions."

6. As noted on Page 3.9-6 of the Draft EIS, the primary difference between daytime and nighttime noises is "transient" noise. This is noise generated by traffic, which is typically heavier during the day than at night.

Responses to Comments Presented at Public Meeting Held October 1, 2003 in Blaine, Washington

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding public meeting transcript.

1. **Mark Lawrence**

1(1) Thank you for your comment.

2. **Rob Pochert**

2(1) Thank you for your comment.

2(2) Thank you for your comment.

3. **Dan Newell**

3(1) Thank you for your comment.

4. **Wyman Bannerman**

4(1) Thank you for your comment.

4(2) The only modification made to the original photo was to add a typical monopole transmission tower. As is typical with photos of snow covered mountains in the distance, the mountains tend to blend with the background. Views with the naked eye reveal much greater contrast.

4(3) If Bonneville, the Applicant, and Alcoa Intalco Works are able to agree on a local remedial action scheme (RAS), generation output at the cogeneration facility would be reduced to the thermal rating of any line between Bonneville's Custer 230-kV station, its Intalco station, and the cogeneration facility. The existing lines are capable of 570 million volt amps, which loosely equates to 570 megawatts. During an outage (planned or unplanned) of any line section, power from the cogeneration project would be reduced to produce a net export of 570 MW. The cogeneration facility could continue to generate enough energy to serve the BP Cherry Point Refinery, supplying from 80 to 90 MW. The cogeneration generators would then produce 650 MW, or 70 MW less than their capacity. During other seasons, Bonneville does not anticipate that the RAS would be required because the ambient temperatures would allow for the additional transfers.

If the cogeneration facility were constructed and in operation, the BP Cherry Point Refinery would no longer be served by Puget Sound Energy (PSE) and its 115-kV system because of the difference in voltage (230 kV and 115 kV). It will no longer be practical for PSE to service the refinery. In Whatcom County, the PSE and Bonneville systems, however, will continue to be interconnected at Bonneville's Custer and Bellingham stations to provide service to the Whatcom County area.

5. **Fred Schuhmacher**

5(1) As noted in Section 2.4.1 of the Draft EIS, air cooling was initially selected to minimize water use. When recycled water became available from Alcoa Intalco Works, water cooling was selected. The benefits of water cooling include a smaller footprint, less visual impact, less total water consumption, and lower cost. The adverse impacts include discharge of blowdown wastewater. These differences are outlined below:

- Plant Footprint: A water cooled plant is more compact than an air cooled plant. The stormwater detention pond can now fit inside the facility footprint after air cooling was replaced with water cooling.
- Visual: The water cooling tower is shorter than air cooled equipment. However, there is likely to be a visible water droplet plume from the water cooling tower, which is not present with an air cooling system.
- Water Reuse: A water reuse project requires less water withdrawal from the Nooksack River. The cost of the water reuse project is about $2 million.
- Cost: Water cooling costs $6 million and air cooling costs $18 million, a difference of $12 million.
- Plant Efficiency: A water cooled plant (consuming 4.5 MW) is 1.6% more efficient than an air cooled plant (which consumes 2.5 MW).

Wastewater discharge from the cogeneration facility is expected to increase discharge from the refinery by about 8% but with the treatment efficiencies of the refinery and dilution within the discharge zone. No adverse impact on the marine environment is anticipated (Kyte, pers. comm., 2004).

In Section 3.2 of the Final EIS under the heading Cooling Tower Steam Plume Fogging and Icing, potential impacts from the cooling tower vapor plume are described. The results of the modeling indicate that there would be a visible vapor plume emanating from the tower with the potential for fogging a couple of hours per year. This vapor plume is not expected to be seen beyond Grandview Road adjacent to the cogeneration facility.

5(2) Thank you for your comment. TransCanada will not be identified as the owner/operator of the cogeneration facility. If there is a change in the ownership of the facility, the current and new owners must get authorization from EFSEC pursuant to applicable laws and rules.

6. **Sam Crawford**

6(1) Thank you for your comment. Please refer to Letter 3, Responses 1 through 13.

6(2) Thank you for your comment. The Applicant will continue its community outreach program during the permitting, construction, and operation of the cogeneration facility.

7. **Frank Eventoff**

7(1) Impacts on the Fraser Valley are analyzed in Section 3.2 of the Final EIS. It was determined that the project emissions would not violate Canadian air quality standards or objectives.

8. **Sandra Abernathy**

8(1) The noise impacts from the project are described in detail in Section 3.9 of the Final EIS. It was demonstrated that noise emissions from the project would meet all regulatory thresholds, and that local residents would not be able to discern any increase above ambient levels.

The impact of air emissions from the project is analyzed in Section 3.2 of the Final EIS. The emissions from the project would meet all U.S. and Canadian regulatory standards and objectives. In addition, the Applicant has committed to removing three refinery boilers, which would greatly reduce NO_x emissions to the airshed.

9. **Wendy Steffensen**

9(1) The project site and laydown areas would be designed with stormwater detention ponds to control the quantity and quality of the stormwater runoff from these areas. These ponds would be designed to reduce peak flows and allow solids to settle out before the water is discharged into the Terrell Creek drainage basin. Most of the water from the project site would flow to a wetland mitigation area, which would further slow the water entering the creek. These modifications will improve the quality and runoff rate of water entering Terrell Creek.

The project will not be a source of acid rain. Nitrogen oxide (NO_x) emissions from the project would be limited to low levels through the use of clean natural gas and Best Available Control Technology (selective catalytic reduction technology). Sulfur dioxide (SO_2) emissions would be low because the natural gas fuel contains minimal sulfur compounds. Unlike coal or fuel oil, natural gas is the lowest sulfur containing fuel available, and it is generally not considered a source of acid rain. Refer to Letter 17, Response 1(27) for additional discussion of air quality impacts.

Disruptions to local freshwater ecosystems from the proposed project emissions are highly unlikely and not anticipated. However, through the site certification process, EFSEC has jurisdiction to stop operations and mitigation of impacts should a *direct* impact on nearby freshwater ecosystems be identified in the future.

9(2) The source of the information in the Draft EIS (Golder 2003) was incorrect. While Washington Department of Fish and Wildlife has identified most of the project site as wetland, no priority habitat has been identified in any portion of the project. The Final EIS has been revised to reflect this information.

9(3) The project will burn a clean fuel, natural gas, and the resulting emissions will be dispersed over a wide area. Only a small fraction of the pollutants would remain in the vicinity of the project. Compared to coal and diesel fuel, natural gas combustion emits significantly lower quantities of criteria and toxic pollutants and, as stated in Response 9(1), is not a significant source of acid rain. Project emissions will be minimized through the use of Best Available Control Technology as explained in Section 3.2 of the Final EIS.

9(4) As stated in note 2a of Table 3.4-4 in the Draft EIS, several trace metals were not detected in the source water (Nooksack River) for the cogeneration facility. To calculate a discharge, the detection limit concentration was used. Those values were then multiplied by the concentration that would result from the cogeneration process (four times the concentration for regeneration water and 15 times the concentration for blowdown water). Note 3 in Table 3.4-5 of the Draft EIS states the treatment efficiency study shows the wastewater treatment plant reduces heavy metals. Thus, the actual discharge concentrations for these trace metals listed in Table 3.4-4 are expected to be much lower than those shown in the table and actually may not be present. Once cogeneration operations begin, the discharge concentrations would be measured and actual concentrations can be determined.

The project would not emit large quantities of heavy metals or persistent biocumulative toxins (PBTs) to the air because the fuel being burned (natural gas) is very clean. These heavy metals and PBTs would be emitted; however, the analysis in Section 3.2 of the Final EIS concludes that toxic air pollutants emissions are below regulatory levels of concern and are not expected to harm the environment.

9(5) As stated in the Sumas Energy 2 Final EIS, "market is expected to encourage the development of efficient power facilities to satisfy increasing power demands and to discourage the development of inefficient and unnecessary facilities. In this market, project developers are expected to move forward with construction of projects only when convinced demand exists for the power the facilities would produce. Project financing, likewise, depends on a demonstration of demand and economic benefit." In short, power generated by the Sumas generation facility is intended to be sold to customers in the Bonneville grid, thereby meeting the customers' needs for power. For purposes of evaluating impacts resulting from both Sumas and the proposed project, the Draft EIS included a cumulative air emissions evaluation on Page 3.2-44 in Table 3.2-28.

The Georgia Strait Crossing (GSX) pipeline is intended to supply natural gas to Vancouver Island, where it may be used for a Canadian generation project. If this pipeline project and a power facility are approved by the Canadian government and constructed, the power produced from these projects would primarily be available to purchasers on Vancouver Island. Cumulative impacts from construction and operation of the GSX pipeline have been addressed the Final EIS. Please refer to Letter 25, Response 3(15).

10. **Alan Van Hook**

10(1) The project would emit only a small quantity of heavy metals because the fuel being burned (natural gas) is very clean. The project would not emit petroleum products but would emit volatile organic compounds (VOCs). The expected emissions of VOCs and heavy metals were modeled, and it was concluded that all air emissions from the project will protect ambient air quality standards and human health.

10(2) If the Alcoa Intalco Works stopped operations, Whatcom County as a whole would experience a reduction of air and water pollutants that are currently emitted by Intalco.

10(3) Thank you for your comment. The alternative analysis completed by the Applicant and described in the Application for Site Certification evaluated the following: (1) potential environmental effects of siting the proposed cogeneration facility elsewhere, and (2) potential water and air quality impacts if the proposed project were not built and power were generated by other means such as the burning of coal or from wind turbines. This analysis concluded that power generated by means other than burning natural gas would most likely result in more environmental impacts than those identified in the Draft EIS.

11. **Cathy Cleveland**

11(1) Modeling the deposition of particulate matter in local watersheds is not warranted because natural gas, a clean fuel, is being burned, and the emissions resulting from natural gas combustion are not considered a significant deposition source of PM_{10}. The particulate matter emissions from the cogeneration project, although modeled as PM_{10} for regulatory purposes, are less than $PM_{2.5}$. This type of fine particulate behaves more like a gas and will disperse to a wider area; it will not deposit close to the site and in Terrell Creek as much as larger particles would.

11(2) Noise monitoring has been addressed in Letter 33, Responses 1 and 2. Prior to the Applicant's most recent noise monitoring, the Applicant met with County officials to discuss the collection of additional noise monitoring data. Mike Torpey and David Hessler met with Whatcom County Council Member Sharon Roy, Whatcom County Attorney David Grant, and Whatcom County Planning and Development Services Noise Specialist Jim Thompson. In light of the County's concern about noise, the Applicant asked the County to select the locations for additional monitoring. The County selected four locations: 8026 Birch Bay Drive, 4825 Alderson Road, Arnie Road east of Blaine Road, and Jackson Road across from the Puget Sound Energy gas metering station. The County did not select a location in the Cottonwood Beach neighborhood. However, the 8026 Birch Bay Drive location is nearby, approximately 3,000 feet south and slightly east of the Cottonwood neighborhood.